Federal/Provincial Research and
Monitoring Coordinating Committee (RMCC)

THE 1990 CANADIAN LONG-RANGE TRANSPORT OF AIR POLLUTANTS AND ACID DEPOSITION ASSESSMENT REPORT

Part 7

SOCIO-ECONOMIC STUDIES

1990

ACID RAIN
PLUIES ACIDES

Province of British Columbia
Ministry of Environment and Parks

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Environment Ontario

Province of Newfoundland
Department of the Environment

Canada

The 1990 Canadian long-range transport of air pollutants and acid deposition assessment report.

FEDERAL/PROVINCIAL

RESEARCH AND MONITORING

COORDINATING COMMITTEE (RMCC)

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FOREWORD

This study is one of a series completed for the 1990 LRTAP Assessment. The principal author is Denise Burich. We would like to thank Ed Weglo, the English editor and Simon Henchiri, the French editor for their assistance in revising the text. Thanks are also due to Ellen Radix, Huguette Tremblay and Lorraine St Denis for their help in preparing the manuscript. We would like to thank, as well, our federal and provincial colleagues, and representatives of public utilities who took the time to review and comment on earlier drafts of the report. This is the first attempt to draw together the story of the industrial response to this program and what has been accomplished to date.

AVANT-PROPOS

Cette étude qui fait partie d'une série de rapports est complétée pour l'Évaluation TADPA de 1990. L'auteure principale est Denise Burich. Nous tenons à remercier Ed Weglo, rédacteur du texte anglais et Simon Henchiri, rédacteur du texte français, pour leur collaboration à la révision du texte. Nous devons également remercier Ellen Radix, Huguette Tremblay et Lorraine Saint-Denis qui ont contribué à préparer le manuscrit. Il nous fait plaisir de remercier, tout aussi bien, nos collègues fédéraux et provinciaux, ainsi que les représentants des services publics qui ont bien voulu s'attarder à revoir et à commenter les premières versions. Ceci représente un premier essai pour rattacher l'histoire de la réponse industrielle à ce programme avec ce qui, de fait, a été réalisé à ce jour.

W. Smith

LRTAP Socioeconomic Coordinator

Coordonnateur socio-économique TADPA

SUMMARY

Due to increasing public concern about the lack of action, this environmental problem had emerged as a Canada-US issue by the early 1980's. In 1984, the Canadian government took the unilateral decision to reduce SO_2 emissions in eastern Canada. Along with 19 other countries, Canada also signed an international protocol in July 1985 to reduce national emissions of sulphur dioxide. Since then in particular, an effort has been mounted in Canada to reduce SO_2 emissions mainly from the processing of ores at smelters and the burning of fuels in electric utility plants. By 1987, Canada reached agreements with the seven easternmost provinces--Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland to limit SO_2 emissions.

Prior to the 1980s, the impaired local air quality around certain of these smelters and plants in Ontario resulted in some emitter initiatives as well as orders at the provincial level to reduce emissions. But a concerted effort to reduce the level of emissions across provinces did not occur until the mid-1980s when Canada's environment Ministers agreed that in 1994, SO_2 emissions should be cut to one-half the level of the 1980 base case in the seven provinces. The purpose of the control program to reduce wet sulphate deposition to a target deposition loading of less than 20 kilograms per hectare per year throughout eastern Canada. To succeed, a 50 percent reduction in the transboundary flow of SO_2 emissions from the United States to Canada is also required.

The table below shows the federal/provincial emissions commitments to meet this target loading, as well as the total 1980 base case emissions and actual annual emissions in 1980, 1985 and 1987. Each province has agreed to reduce total annual SO_2 emissions from the 1980 base case figure listed to the commitment figure listed for 1990 or 1994.

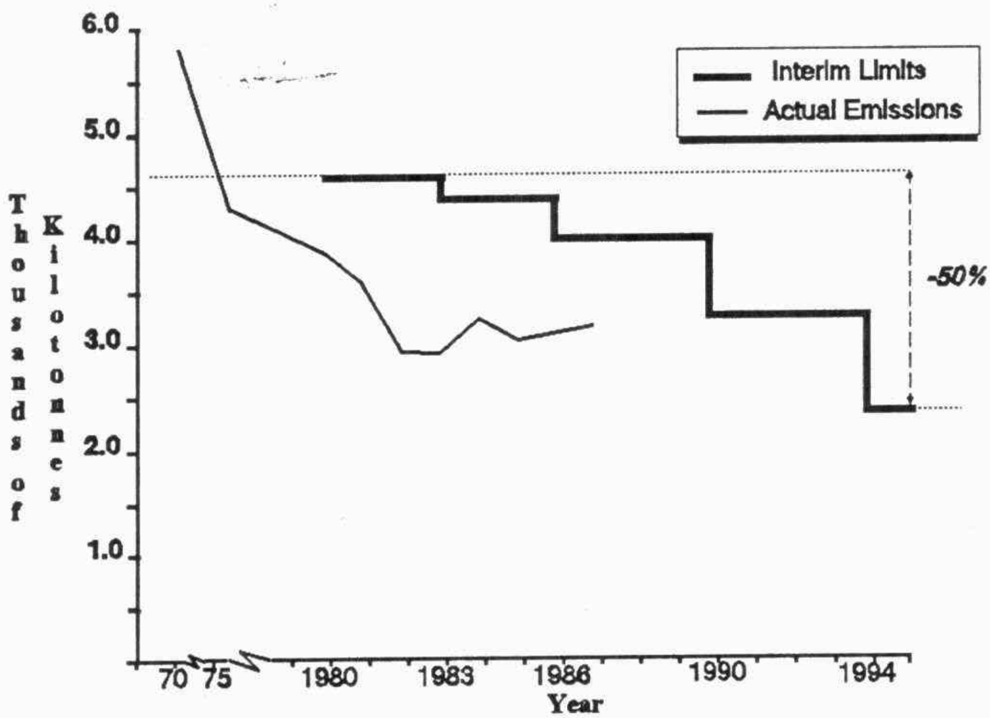
ANNUAL SO_2 EMISSION LIMITS AND EMISSIONS BY PROVINCE
(Kilotonnes)

PROVINCE	BASE	COMMITMENT[a]		ACTUAL EMISSIONS		
	1980	1990	1994	1980	1985	1987[b]
Manitoba	738		550	484	469	559
Ontario	2,194		885	1,764	1,457	1,399
Quebec	1,085	600	600	1,098	693	660
New Brunswick	215		185	220	138	216
Nova Scotia	219		204	193	170	178
Prince Edward Island	6		5	5	2	3
Newfoundland	59		45	56	43	51
TOTAL	4,516	600	2,474	3,820	2,972	3,066

[a] 174 kilotonnes have yet to be allocated for reduction
[b] preliminary figures only

In Quebec, the reductions and legal upper limits on SO_2 emissions come into effect in 1990. In all other provinces, the reductions and restrictions on emissions will come into effect in 1994. Before 1994, some interim reductions are required of the major emitters in Ontario as well as at Inco in Thompson, Manitoba, as reflected in the figure below which depicts the interim limits and the upper limit as well as actual emissions in recent years.

LOWERING BASE CASE LEVEL SO_2 EMISSIONS IN EASTERN CANADA (1980 -1994)



To attain reduced rates of emissions, some companies have already achieved reductions which are significant when compared with earlier years. At Falconbridge, for example, the SO_2 emissions per tonne of nickel produced prior to 1955 ranged as high as 15 tonnes, but in 1988 the emissions were down to less than two tonnes of SO_2 per tonne of nickel produced. Ontario Hydro, on the other hand, has reduced the average sulphur content of the coal used in its thermal generating stations from 2.4 percent in 1976 to about 1.3 percent in 1988, and expects a further reduction to 1.0 percent in 1990.

The SO_2 control program is comprised of a mix of negotiated and regulatory instruments. At the national level, the federal and provincial governments have used a set of seven negotiated agreements (including provisions for loans to smelters in Manitoba, Ontario and Quebec) to reduce emissions in the seven provinces. At the provincial level, the main measures used to reduce industry and company emissions include:

- o regulatory instruments in Manitoba, Ontario and Quebec with some provisions for fines if upper limits on emissions are not met; and
- o negotiated agreements in the Atlantic provinces.

The smelters processing ores with high sulphur content can reduce emissions and still sustain production by reducing the amount of sulphur-bearing minerals in their feedstocks, by minimizing the formation of SO_2 during production using state-of-the-art technologies and/or by capturing more of the SO_2 in the waste gas stream. Alternatively, they can reduce emissions by reducing production.

Utilities can opt to displace fossil fuel generation with other forms of electrical generation, purchase electricity from hydroelectric-based systems, lower the sulphur content of the fuels they burn, and/or retrofit emission control technology at existing fossil fuel generating stations. Also, the introduction of demand management initiatives could reduce the need for fossil fuel generation. Outright closure of coal-fired or oil-fired generating stations is not necessary to meet the 1994 upper limits.

The smelters and utilities subject to emission controls have undertaken to limit their emissions of SO_2 to specific amounts by 1994. In some cases companies have indicated they may be able to reduce emissions further after 1994. There are technical and operational factors, that must be resolved in the interim.

Together, the companies will invest about $1,734 million in capital projects from 1987 through 1993 to meet the 1994 upper limits on SO_2 emissions. The average annual investment over the period will be $248 million. The avarage annual investment in capital projects will be higher during the final four years, when it will run at about $352 million each year. Investments in research and development initiatives by the major emitters are additional to the investments in capital projects.

Capital investments will continue after the 1994 upper limits come into force. Both Ontario Hydro and Nova Scotia Power, for example, have indicated that their abatement projects will necessitate further investments. To allow for growth in the demand for electricity, Ontario Hydro will continue to invest an average of $206 million per year in capital projects from 1994 through 1998. Nova Scotia Power will also invest another $170 million in total from 1994 through 2010.

When established, the target deposition load was considered sufficient to protect all moderately sensitive areas, ie., freshwater aquatic systems in areas without a natural capability to neutralize acidic input due to wet sulphate deposition rates in excess of 20 kilograms per hectare per year. The results of ongoing biophysical research in Canada suggest that a lower level of deposition may be required in some areas.

By 1994, the elements of Canada's current emissions control program will be fully implemented; the corresponding reductions in the United States, which are not dealt with in this report, are expected to be implemented by the year 2000. As these important dates grow nearer, there will be greater opportunity to re-evaluate the domestic actions being taken and only then will it be clear whether further reductions will be needed to attain acceptable control of SO_2 emissions.

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7.1 INTRODUCTION

Over the last several decades, emissions from the burning of fossil fuels, the smelting of metals and other industrial processes reached levels that directly or indirectly threaten some of Canada's aquatic, terrestrial, human and cultural resources. Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland are the provinces which are most heavily exposed to acidic deposition.

In response to growing public concern and to meet recent international commitments, Canada's environment Ministers, in the mid-1980s, resolved to reduce total annual emissions of SO_2 in the seven easternmost provinces. They announced that in 1994, annual emissions in the seven provinces would be cut to one-half the level of the 1980 base case (see Table 7.1 and Figure 7.1). There was widespread agreement that 1980 emissions should be selected as a base case year against which future emissions would be measured, inasmuch as it was one of the first years for which extensive emissions data had been collected. In some cases the upper limits already imposed on the major emitters at that time were used, while in other cases the actual emission values were used to determine the 1980 base case. In general, actual emissions for 1980 were lower than the base case level.

TABLE 7.1 - **ANNUAL SO_2 EMISSION LIMITS AND EMISSIONS BY PROVINCE**
(Kilotonnes)

PROVINCE	BASE	COMMITMENT[a]		ACTUAL EMISSIONS		
	1980	1990	1994	1980	1985	1987[b]
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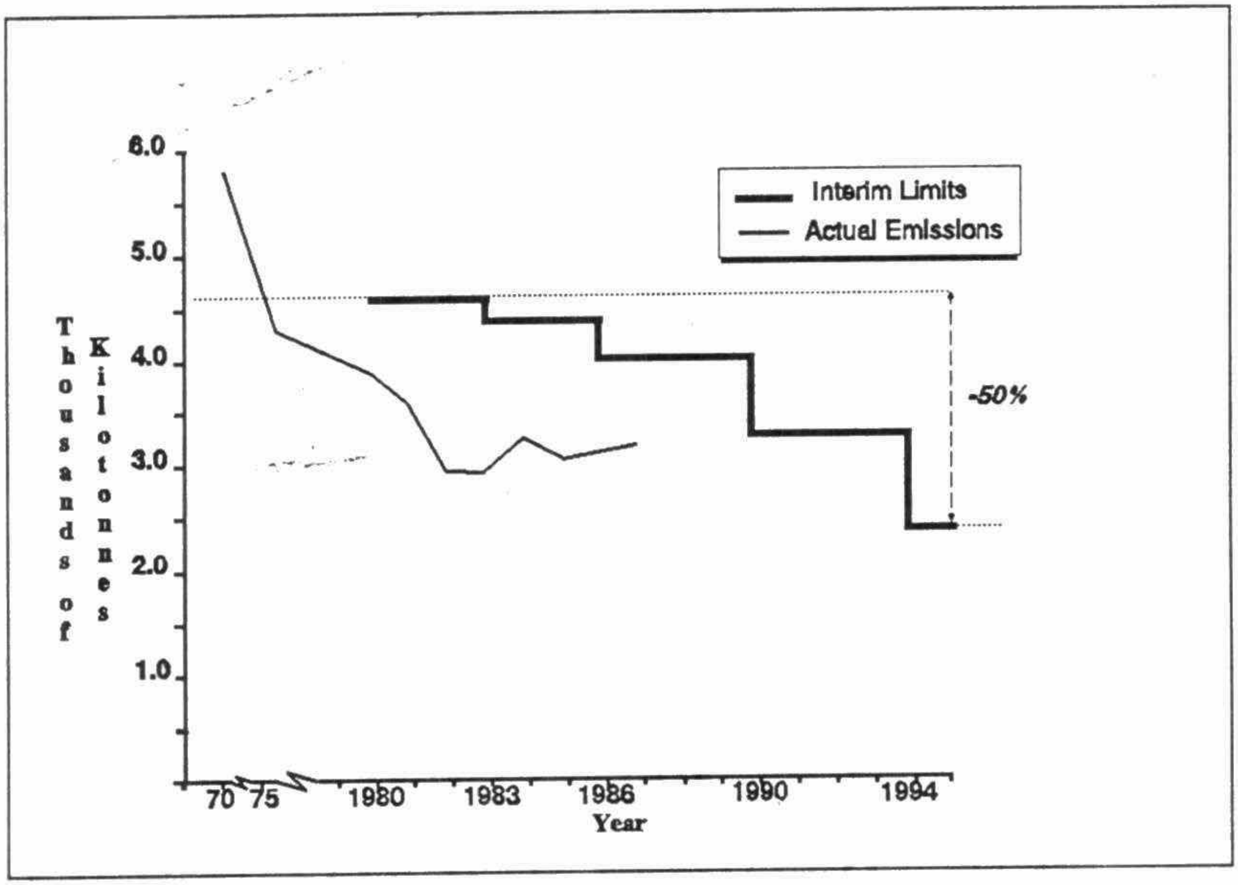
TOTAL	4,516	600	2,474	3,820	2,972	3,066

[a] 174 kilotonnes have yet to be allocated for reduction
[b] preliminary figures only

FIGURE 7.1 - LOWERING THE BASE CASE LEVEL SO_2 EMISSIONS IN EASTERN CANADA (1980 -1994)



The table shows that actual SO_2 emissions in the seven provinces totalled 3,820 kilotonnes in 1980. Ontario and Quebec accounted for 75 percent of these emissions; Ontario's share alone was 46 percent. The major emitters are found within the mining and energy sectors. Smelting processes for sulphur bearing copper, nickel and zinc ores were the major cause of emissions in Manitoba, Ontario and Quebec; coal-fired electric generating stations were the major secondary source of emissions in Ontario. In the four Atlantic provinces, however, sulphur rich coal and sulphur rich oil used to fire conventional thermal-electric generating stations were the major causes of emissions.

7.1.1 THE DEVELOPMENT OF CANADA'S SO_2 CONTROL PROGRAM

The problems associated with the long range transport of airborne pollutants (LRTAP) are world wide. Canada was one of the early supporters of an international protocol to both study and eventually reduce emissions of SO_2 and other primary pollutants. Thus, Canada's SO_2 control program is in part intended to meet its international obligations as well as to reduce the effects of SO_2 emissions in eastern Canada.

The government directives that comprise Canada's SO_2 control program, including policies, programs, legislation and agreements, are identified in Table 7.2. The federal government signed agreements with each of the seven easternmost provinces respecting SO_2 reductions to formalize the emissions control program. In the agreements, commitments are established for new annual upper limits on provincial emissions of SO_2 beginning in 1994. All of the agreements, with the exception of the Canada-Ontario agreement which does not have an expiry date, lapse at the end of 1994 and must be renewed.

TABLE 7.2 - **CANADA'S SO_2 CONTROL PROGRAM - GOVERNMENT DIRECTIVES**

YEAR	POLICY	PROGRAM	LEGISLATION	JOINT AGREEMENTS
1985	50% reduction in eastern Canada's SO_2 emissions by 1994[a]	Ont: Countdown Acid Rain (APIOS) Canada: LRTAP IV	Que: Atmosphere Quality Reg Ont: Reg 660/85 Ont: Reg 661/85 Ont: Reg 662/85 Ont: Reg 663/85 Ont: Reg 16/86	
1987			Ont: Reg 281/87[b]	Canada/Nfld Canada/PEI Canada/NB Canada/Quebec Canada/Ontario Canada/Manitoba
1988			Man: Reg 165/88	Canada/NS

[a] National commitment
[b] Regulation 281/87 revises Reg 662/85 issued earlier in 1985

In Canada, the provinces have basic constitutional jurisdiction over most stationary sources of air pollution. Consequently, each of the provinces concerned is responsible for allocating specific reductions in emissions to industries or companies within their jurisdictions.

In Manitoba, Ontario and Quebec, the provincial governments introduced regulations that establish new legal upper limits on the future annual SO_2 emissions at the operations of selected companies while simultaneously lowering their annual allowable rates of emissions from 1980 base levels.

In New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland, the provincial governments have negotiated reductions with the major emitters. The process in the Atlantic provinces is ongoing to ensure that the targets are met.

Directives in Ontario, Quebec and Newfoundland also cover various new facilities. Ontario, for example, imposes emissions control requirements on new facilities during the environmental assessment or the construction approvals process. In addition to the regulation on utility emissions, fuels used in new or modified boilers in Ontario must meet a one percent sulphur content constraint. Alternatively, an equivalent amount of SO_2 can be removed from the flue gas of new or modified boilers. In Quebec, on the other hand, new smelters must control 95 percent of the sulphur contained in the ore concentrate processed. In Newfoundland, under the federal-provincial agreement, all new industry established within the province is required to use state-of-the-art emission control technology to minimize emissions.

Actions taken at the federal level in support of the objective of a 50 percent reduction in SO_2 emissions include:

- o the development and application of new process and pollution control technologies - $150 million to assist smelters implement specific abatement programs and $25 million for technology development and demonstration projects at non-ferrous smelters;
- o the increased use of low sulphur coal, and the cleaning and blending of coals to achieve a more efficient use of coal by utilities - $70 million;
- o research and monitoring to improve understanding of the impacts of wet sulphate deposition, and to verify the effectiveness of emissions reductions - $90 million; and
- o negotiations to reduce the transboundary flow of U.S. SO_2 emissions into eastern Canada to no more than 2,000 kilotonnes (Canada, Environment Canada, n.d).

The directives that will restrict annual SO_2 emissions in the seven easternmost provinces of Canada are in addition to standards and controls which safeguard ambient air quality that are outside the scope of this report.

7.1.2 SO_2 REDUCTION PROGRAM BY MAJOR EMITTERS

At the provincial level, eight companies will contribute the most to ensuring that the new upper limit on SO_2 emissions in the seven easternmost provinces is not exceeded beginning in 1994. Six large copper, nickel and zinc smelters, one iron ore sintering plant and three provincial utilities are involved in the initiatives for SO_2 control, including:

Smelters
- o Hudson Bay Mining and Smelting (HBMS), Flin Flon, Manitoba;
- o Inco, Thompson, Manitoba;
- o Inco, Sudbury, Ontario;
- o Falconbridge[1], Falconbridge, Ontario;
- o Noranda, Rouyn, Quebec;
- o Noranda, Murdochville, Quebec;

Sintering Plant
- o Algoma[2], Wawa, Ontario;

Electric Utilities
- o Ontario Hydro, Ontario;
- o New Brunswick Electric Power Commission (NBEPC), New Brunswick; and
- o Nova Scotia Power Corporation (NSPC), Nova Scotia.

Table 7.3 shows actual plant emissions by company and the new emissions limits established for 1990 (where applicable) and 1994. Inco's smelter complex at Sudbury is the largest single source of SO_2 emissions in Canada, followed by the two Manitoba smelters and Noranda's complex in Rouyn. Two of Ontario Hydro's thermal generating stations, Nanticoke and Lambton, are the first and second largest single-sources of SO_2 emissions among the utilities. Dalhousie #2, owned by New Brunswick Power, is the third largest single-source of emissions among the three utilities considered in this report.

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[1] Purchased in 1989 by Noranda Inc. and Trelleborg AB of Sweden.

[2] Purchased by Dofasco Inc. in 1988.

TABLE 7.3 - **ANNUAL SO_2 EMISSION LEVELS AND LIMITS OF MAJOR EMITTERS (Kilotonnes)**

COMPANY	ACTUAL EMISSIONS			UPPER LIMITS	
	1980	1985	1987	1990[a]	1994
HBMS	248	270	287	293	220
Inco (T)	219	188	252	300	220
Inco (S)	812	695	659	685	265
Falconbridge	123	74	72	154	100
Noranda (R)	552	436	412	276	276
Noranda (M)	91	43	45	65	65
Algoma (W)	161	116	85	180	125
Ontario Hydro	396	337	332	240	175
NBEPC	122	94	115	--	130
NSPC	125	130	135	--	160

[a] 1990 interim commitments imposed on industry by provinces

During the 1970s, Inco (Sudbury), Falconbridge and Algoma were in the throes of programs initiated to improve local air quality. The Government of Ontario issued new control orders for Inco (Sudbury), Falconbridge and Ontario Hydro in 1980 establishing new emission limits in the latter half of the 1980s to deal with the long range transport problem. Inco (Sudbury), Falconbridge and Ontario Hydro were working to reduce emissions by the mid-1980s when the Government of Ontario passed a new set of regulations in 1985 requiring Inco (Sudbury), Falconbridge, Algoma and Ontario Hydro to reduce emissions even more by 1994.

All major emitters, with the exception of HBMS, Inco (Thompson) and Nova Scotia Power, recorded lower emissions in 1987 than the levels they recorded for 1980. However, while the provincial emission objectives for Nova Scotia and New Brunswick decrease for 1994, both utilities were assigned higher 1994 emissions than their 1980 actuals. Planned corporate actions covering new generating capacity and the use of locally available fuels high in sulphur content necessitated these new objectives in 1994. At Murdochville, an operating acid plant will enable Noranda to sustain its upper limit on emissions through 1994 and beyond. The remaining companies are acting to equal or better their performance of 1980.

7.1.3 FRAMEWORK FOR ANALYSIS

The major SO_2 emitters can reduce and/or minimize emissions at their operations through supply side initiatives or demand side initiatives. On the supply side, each emitter might alter a number of the existing factors of production within its operations to reduce emissions. These alterations might include changes to:

- o existing capital or plant;
- o fossil fuel inputs (utilities);
- o non-ferrous ore (smelters) and ferrous ore (sintering plant) inputs;
- o labour; and/or
- o research and development.

On the demand side, the major emitters might initiate activities to promote the conservation or more efficient use of their products by consumers. Such initiatives are currently initiated as a result of public policy and are more prevalent among utilities than smelters.

Table 7.4 conceptualizes emissions control measures for the major emitters by factor of production and the hypothetical time in which the changes to the factors of production can take place. The ability to elicit changes in consumer patterns and/or behaviour is not a factor of production and is treated in the framework under the 'socioeconomic' factor. The major emitters will implement short term, medium term or long term emissions control measures, or some mix thereof, to restrict emissions to the required levels in 1994 given a desirable level of capital utilization.

Short Term Emissions Control Measures

Short term measures can be implemented without undue delay and usually involve changes to variable factors of production such as resource and labour inputs. The physical condition of the plant (buildings and equipment) will not be altered, but plant capacity may be reduced or shut down. In practice, short term measures might be implemented in conjunction with medium term solutions. For example, the plant may have to be modified before resource inputs at the smelters or the utilities can be changed or wash plant capacity may have to be expanded to clean additional quantities of coal.

The length of existing resource sales or purchase contracts can serve as a barrier to the implementation of short term measures that could improve environmental performance. A 20-year coal purchase contract between a utility and a coal mining company will lock the utility into taking delivery of a higher sulphur content coal. Similarly, an exporting utility may have to use a coal-fired generating station to meet its contractual obligations

TABLE 7.4 - **CONCEPTUAL FRAMEWORK**

FACTORS	**TIME FRAME** Short Term	Medium Term	Long Term
Existing Capital or Plant	-cut back production -shut down plant	-modify plant or equipment -build scrubber -build acid plant	-replace plant -alter generating mix
New Plant or Added Electricity Supply	-purchase out-of-province electricity	-add cleaner capacity: fossil, non-fossil, non-utility generation	-add cleaner capacity: advanced combustion technology, experimental technology
Fuel Supply and Other Resource Inputs	-clean and blend coals -use of low sulphur fuels -inject sorbent into furnace	-use of fuel technology	-use of advanced fuel and advanced coal cleaning technologies -exploration
Metal Ores/ Concentrate (feedstock)	-use high grade ores	-use of pyrrhotite rejection	-use of improved pyrrhotite rejection -exploration
Socioeconomic			-promote demand management and recycling
Research and Development			-laboratory and industrial scale projects -technology assessments

with another utility simply because another way of generating and then transmitting the power to the purchasing utility does not exist.

Medium Term Emissions Control Measures

Medium term measures can be capital intensive but are somewhat more immediate than long term measures. They may involve modifications to existing plant or the addition of new structures to modern or aging plants to improve environmental performance. A lead time is required, first to plan the changes or additions to operations, and then to make the changes. Basic research and development is most likely complete and the preferred technology is available for implementation.

Long Term Emissions Control Measures

Long term measures include:

- o capital intensive measures involving plant replacement;
- o exploration for and delineation of fossil fuel reserves and ore reserves with lower sulphur contents;
- o changes in social patterns of consumption and energy efficiency, including demand management initiatives; and/or
- o other measures that take effect only after a number of years have elapsed.

The first two measures above are self explanatory. With regard to the third measure, demand management initiatives are designated as long term measures because it is primarily in the aggregate, rather than on an individual basis, that these initiatives can have an impact on demand. Utilities employ demand management initiatives to influence the pattern and quantity of electricity demanded by consumers. Examples of such initiatives include load shifting from peak to off-peak hours and utility stimulated energy conservation programs for residential, commercial and industrial consumers. The timing and the magnitude of impending benefits are largely dependent on consumer response through time, which in turn is critically dependent on the social framework[3] established by governments.

In the latter case, research, development and demonstration work needs to be completed for new process and combustion technologies before the new technologies can be successfully implemented or made available for commercial use. Advanced combustion technologies include circulating fluidized bed combustion (CFB), pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC). There are varying degrees of risk and uncertainty attached to the use of advanced combustion

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[3] Includes elements such as energy policy, water resources policy, transportation policy, land use and urban development, building codes and control of wasteful manufacturing and consumption practices.

technologies. The advanced combustion technologies become designated for possible future use due to a lack of domestic operating experience and the unavailability of ten to twenty year operational histories. The advanced cleaning of coals includes chemical, biological or advanced physical cleaning of coals.

7.1.4 PURPOSE AND ORGANISATION OF REPORT

This report is the first attempt to compile the industrial impacts associated with the SO_2 control program in seven of Canada's provinces. It serves to identify the control measures that will enable the major emitters to reduce their emissions in 1994 as well as some of the impacts of the controls on industrial operations; it reports on the progress made to date in reaching the emissions limits imposed for 1994; and it identifies some of the barriers that could be encountered at the industrial level if further limits are required.

Some basic economic concepts have been used in the report to organise and highlight some of the more complex themes. As such, the report points to some of the complexities that must be dealt with in preparing an industrial impact assessment and in the mixing and matching of measures to improve controls.

The report began with an overview of the SO_2 reduction program and the framework within which the program is to be analysed. The industrial impacts are presented in two sections, one on the smelter and sintering plant complexes and a second on the electric utilities. In both sections, the ability to control emissions, the capital investments planned, the operational effects, and corporate ability to finance emission controls are presented. The report closes with a discussion on future research directions.

7.2 SMELTER AND SINTERING PLANT COMPLEXES

Smelting is defined as a process by which a metal is recovered from a concentrate. Metals are recovered from concentrate by heating the concentrate beyond its melting point in the presence of air, fuel and fluxing agents. To recover the metal, the ore is processed and upgraded in several sequential stages from mining and milling through to roasting, smelting, converting and refining. Each stage from roasting to refining is designed and operated to reduce the impurities in the concentrate further by removing sulphur as gaseous SO_2 and the metallic impurities as slag. Air supplied to the roasting, smelting and converting stages of the smelting operations determines the volume and concentration of SO_2 gas produced.

Sulphides are compounds of sulphur and other elements. Pentlandite is a nickel-iron sulphide; chalcopyrite is a copper-iron sulphide; sphalerite is a zinc sulphide; and pyrrhotite is an iron sulphide. Whereas pentlandite, chalcopyrite and sphalerite are ore minerals of interest to the smelters, pyrrhotite is not inasmuch as it is a significant source of sulphur in nickel and copper ores.

The basics of smelting are provided in Appendix 7.A.1. Readers unfamiliar with the smelting process may find the descriptions provided on mining, milling, roasting, smelting, converting and refining of some use in understanding where SO_2 gas is generated within smelter complexes and in understanding the emission control measures being adopted by smelters.

Table 7.5 lists the metal production in kilotonnes per year and the corresponding ratio of SO_2 emissions to metal production for each smelter in 1980 and 1987. The ratios for 1987 are lower than those for 1980 except at HBMS and Noranda (Rouyn). Among the major smelting sources of emissions considered in this report, Noranda (Murdochville) has the lowest ratio and Falconbridge the second lowest. Inco's smelter in Thompson has the highest ratio; however, its ratio for 1987 is down from that for 1980.

These ratios provide a rough comparative guide. The nature of the ore concentrate and the metallurgy used at individual smelters determine the control measures that can be used to lower emissions. These factors also affect the emission reductions available for the same level of financial and technological commitment at each of the complexes.

Table 7.6 summarizes the strategies HBMS, Inco (Thompson), Inco (Sudbury), Falconbridge, Noranda (Rouyn), Noranda (Murdochville) and Algoma will follow to meet their upper limits on emissions in 1994.

TABLE 7.5 - METALS PRODUCTION AND SO_2 EMISSIONS - SMELTER COMPLEXES

COMPANY	PRIMARY PRODUCTION	SMELTER CAPACITY[a]	% SULPHUR CONTENT		PRODUCTION AND RATIO OF EMISSIONS			
			Ore	Concentrate	1980		1987	
					(1)	(2)	(1)	(2)
HBMS	copper/zinc	160	10-20	28-35	135	1.83	152	2.11
Inco (T)	nickel	64		27	43	5.06	u/k	3.95
Inco (S)	copper/nickel	264		31-34	258	2.38	233	2.12
Falconbridge	nickel/copper	71	12	30	54	2.30	43	1.65
Noranda (R)	copper	213		32-33	201	2.64	158	2.73
Noranda (M)	copper	60		30-36	63	1.44	60	0.83

(Source: Paine, 1989)

[a] kilotonnes per year

(1) actual metal production in kilotonnes
(2) ratio of SO_2 emissions in kilotonnes to metal production in kilotonnes

TABLE 7.6 - PRODUCTION AND EMISSIONS CONTROL STRATEGIES - SMELTER AND SINTERING PLANT COMPLEXES

STRATEGY	COMPANIES PURSUING STRATEGY
I) Sustain Production Level	
a) lower sulphur content of concentrates entering the processing stages	-Inco (T) -Inco (S) -Falconbridge -Algoma
b) decrease the formation of SO_2 gas in roasting and smelting stages	-HBMS -Inco (S)
c) capture more of the SO_2 gas before release of the waste gas to the atmosphere	-Inco (S) -Falconbridge -Noranda (R) -Noranda (M)
d) lower sulphur content of other smelter feeds	-Inco (T)
II) Lower Production Level	
a) lower capacity	-Algoma
b) close down	

Pyrrhotite rejection sends sulphur to tailings during the milling stage and thus prevents the sulphides in the rejected material from reaching the smelter and from being converted to SO_2 gas. Conventional ore processing operations remove much of the pyrrhotite from the concentrate before it is shipped to the smelter. However, if additional pyrrhotite can be removed during the milling operation there will be less sulphide mineral available to form SO_2 during the roasting, smelting and converting stages.

At nickel smelters, the ratio of pyrrhotite to pentlandite in the ores impacts considerably on the degree of pyrrhotite rejection possible. But the pyrrhotite rejection process is accompanied by metal losses. At some point, the amount of nickel lost to tailings due to increased levels of pyrrhotite rejection becomes significant and economically unacceptable to the smelters. Consequently, a mix of emissions control measures is required by smelters practising pyrrhotite rejection if emissions are to be lowered by up to 70 or 90 percent.

Smelters with a high concentration of SO_2 in their waste gas streams can utilize acid plants or liquid SO_2 plants to fix SO_2 as sulphuric acid or as liquid SO_2. While both products are nominally saleable, viable product markets do not exist for the two Manitoba smelters. Smelters with weak waste gas streams can modify their processes to increase the concentration of SO_2 in the waste gas or substitute new processes for older ones to produce higher concentrations of SO_2 in the waste gas.

In some cases, increasing the degree (or extent) of roasting will produce greater amounts of SO_2 within an operation, allowing for easier and more efficient capture of the gas. The SO_2 gas produced is more amenable to capture if a fluid bed roaster is used rather than another type of roaster. In other cases, companies may have to change the processes used to roast, smelt and convert the concentrate to reduce emissions without reducing production. Copper and nickel concentrates, for example, could be combined and smelted together in an oxygen flash furnace instead of smelting the two concentrates separately. Inco developed this smelter technology in the 1980s. Alternatively, scrubbers can be installed to remove low strength SO_2 from the waste gas.

7.2.1 EMISSIONS CONTROL AND PLANT MODERNIZATIONS

HBMS, Inco, Falconbridge and Noranda have decided upon a combination of measures to lower SO_2 emissions at their smelters that include modifying or modernizing existing smelting processes, lowering the sulphide content of concentrates, and adding to acid production capacity. Algoma, on the other hand, reduced production at Wawa in the mid-1980s due to market and plant conditions.

The control measures and R & D initiatives being implemented by the companies are identified in Table 7.7. Where these measures are a part of ongoing initiatives at some

smelters, the earlier efforts to reduce emissions are summarized in Appendix 7.A.2 for the interested reader. Descriptions of several emission control measures are provided in Appendix 7.A.3.

At Inco's Sudbury smelter, better pyrrhotite rejection will reduce incoming sulphur levels in the smelter feed. At the same time, new bulk smelting of the copper-nickel concentrates will produce higher concentrations of SO_2 gas. The gas will be processed by a new double-contact acid plant to produce greater quantities of sulphuric acid for sale. Liquid SO_2 production also increases.

TABLE 7.7 - EMISSIONS CONTROL - SMELTER AND SINTERING PLANT COMPLEXES

Inco Ltd. (Sudbury, Ontario)

FACTORS	TIME FRAME		
	Short Term	Medium Term	Long Term
Existing Capital or Plant	-Frood-Stobie Mill to be shut down in conjunction with mill rationalization program -Copper Cliff Mill to be used for dewatering purposes only	-redesigned higher efficiency magnetic separators for the separation of magnetic pyrrhotite from ground ore	-new bulk (Cu-Ni) smelting process -double contact acid plant to replace existing acid plant -new milling technology
Metal Ores/ Concentrates (feedstock)		-pyrrhotite rejection	
Research and Development			-to capture more off-gas from fluid bed roasters (1994+)

TABLE 7.7 - **EMISSIONS CONTROL - SMELTER AND SINTERING PLANT COMPLEXES** (continued)

Falconbridge Ltd. (Falconbridge, Ontario)

FACTORS	TIME FRAME Short Term	 Medium Term	 Long Term
Existing Capital or Plant		-modification to acid plant -modification to smelter improves roast technology	-Strathcona Mill modernization
Metal Ores/ Concentrates (feedstock)		-pyrrhotite rejection	
Research and Development			-increased roasting (1994+) -improved pyrrhotite rejection (1994+)

Noranda (Rouyn, Quebec)

FACTORS	TIME FRAME Short Term	 Medium Term	 Long Term
Existing Capital or Plant		-acid plant (1990)	
Metal Ores/ Concentrates (feedstock)			
Research and Development			-capture more off-gas from converter for fixation at acid plant (1994+)

TABLE 7.7 - **EMISSIONS CONTROL - SMELTER AND SINTERING PLANT COMPLEXES** (continued)

Hudson Bay Mining and Smelting (Flin Flon, Manitoba)

FACTORS	**TIME FRAME** Short Term	Medium Term	Long Term
Existing Capital or Plant			-new zinc pressure leaching plant -new Noranda Reactor
Metal Ores/ Concentrates (feedstock)			
Research and Development			

Inco Ltd. (Thompson, Manitoba)

FACTORS	**TIME FRAME** Short Term	Medium Term	Long Term
Existing Capital or Plant			
Metal Ores/ Concentrates (feedstock)		-pyrrhotite rejection	
Research and Development			-reducing the costs of emissions containment

TABLE 7.7 - EMISSIONS CONTROL - SMELTER AND SINTERING PLANT COMPLEXES (continued)

Algoma (Wawa, Ontario)

FACTORS	TIME FRAME		
	Short Term	**Medium Term**	**Long Term**
Existing Capital or Plant	-cut back production		
Iron Ores (feedstock)	-low sulphur iron oxides -other sulphur free by-products		
Research and Development			

Falconbridge will reduce chalcopyrite concentrate in the smelter feed beginning in 1989, thereby reducing SO_2 emissions by about seven kilotonnes annually. In addition, planned changes to its smelter will allow a moderately higher level of sulphur elimination in fluid bed roasting, concurrently increasing the amount of SO_2 gas available for fixing at an existing acid plant.

In Quebec, Noranda has constructed an acid plant at Rouyn to reduce emissions at the smelter by 50 percent. The new acid plant came on stream in November 1989. Previously, all SO_2 gases at Rouyn were released directly to the atmosphere.

In Manitoba, HBMS plans to modernize its operations to reduce emissions; all SO_2 gases are released currently to the atmosphere. The company may construct a new zinc pressure leaching plant, thus eliminating the need for roasting and conventional leaching, traditional sources of SO_2 emissions at the smelter. Waste SO_2 gas will no longer be produced as a by-product of zinc processing once the new process is installed. Instead, impure elemental sulphur will be produced as a by-product of the zinc pressure leaching process.

The company also will install a Noranda Reactor for the copper circuits, replacing existing reverberatory furnaces. This latter action will allow HBMS to fix SO_2 gas as sulphuric acid in the future if desirable and if markets are available. At such time, an acid plant would have to be constructed. At Inco (Thompson), all SO_2 gases are released to the atmosphere currently. Incoming sulphur levels in the smelter feed, however, are reduced by rejecting pyrrhotite to tailings. As of 1990, this control measure lowers annual SO_2

emissions to about 55 percent of the levels seen in the 1970s when pyrrhotite rejection was not practised. Under the Manitoba regulation, Inco must lower annual SO_2 emissions between 1990 and 1993 to only 300 kilotonnes.

The company informed the Government of Manitoba and the Manitoba Clean Air Commission in 1987/88 that it cannot economically attain the 220-kilotonne upper limit set to take effect in 1994. More recently, in a report prepared for the Government of Manitoba, Inco (1989c) reported that the lone economically practical means of reducing SO_2 emissions from its Thompson smelter is to reject pyrrhotite to tailings. The rejection of pyrrhotite to tailings, however, results in an increase in nickel losses that is unacceptable to the company. At the same time, beginning in 1990, Inco will process increasing quantities of ultramafic ores requiring further changes to its mill and smelter facilities. The ultramafic ores have a higher sulphur to nickel ratio than the current Thompson type ores.

Inco (1989c) concluded that:

- o both limestone scrubbing of its smelter gases and the production of saleable by-products as a means of reducing its SO_2 emissions are impractical control measures;
- o it cannot attain the new annual upper limit by 1994 using pyrrhotite rejection alone without simultaneously reducing production below the smelter's nameplate capacity;
- o to attain the new annual upper limit, the most promising measures include pyrrhotite rejection combined with the containment of sulphur from refinery anode slimes;
- o if successful technology cannot be developed for 1994, the smelter can only meet the annual upper limit by reducing production below the smelter's nameplate capacity; and
- o due to its inexperience with ultramafic ores, a further two years of research, development and engineering is required to develop the information upon which an emission control strategy can be based.

Inco is continuing its research program to look for solutions. The Government of Manitoba will determine if the 220-kilotonne upper limit is too restrictive once Inco has completed further research.

In 1994, Inco (Sudbury), Falconbridge and Noranda (Rouyn) will have efficient production processes in place and will operate acid plants to minimize their annual emissions. HBMS will have an efficient plant but can forego capturing and treating waste SO_2 gas to meet its upper limit on emissions. Inco (Thompson) and Algoma will continue to use less efficient production processes and, also, can forego capturing and treating waste SO_2 gas to meet their upper limits. Noranda (Murdochville), on the otherhand, will continue to use a less efficient plant but also uses an acid plant built in the early 1980s to capture and treat waste SO_2 gas to meet its upper limit. Table 7.8 shows the plant improvements anticipated at each company.

TABLE 7.8 - **PLANT AND EMISSION CONTROL UPGRADES FOR SMELTER AND SINTERING PLANT COMPLEXES**

PRE-PROGRAM (1980)		POST-PROGRAM (1994+)		
		Outmoded	**Modern**	**Updated**
Outmoded	Inco (T)	Inco (T)		
	Noranda (M)	Noranda (M)		
	Algoma	Algoma		
	Inco (S)			Inco (S)
	HBMS		HBMS	
Modern	Noranda (R)			Noranda (R)
Updated	Falconbridge			Falconbridge

Where:

An <u>outmoded plant</u> is basically an 'old plant' that uses less efficient production processes by current technical and environmental standards. The plant generates large quantities of waste gas, some of which may be treated or utilized for acid production.

A <u>modern plant</u> is one that already employs an efficient and a cleaner smelting process because it was built or modernized recently, but still releases all SO_2 gas produced during metal recovery to the atmosphere without treatment. Add-ons such as acid plants and scrubbers could lower emissions.

An <u>updated plant</u> is one that employs both an efficient and a cleaner smelting process, and uses add-ons to capture and treat SO_2 gas before releasing the remaining waste gas to the atmosphere. Where acid plants are being used, a scrubber could be added to treat residual emissions. Eventually, R & D breakthroughs will be required if emission levels must be lowered further without adversely affecting production levels.

7.2.2 PLANNED CAPITAL INVESTMENTS

Inco (Sudbury), Falconbridge and Noranda have firm plans for capital investments in the late 1980s and the first half of the 1990s. HBMS and Inco (Thompson) have estimated the capital investments that may be required to reduce emissions by 1994 but have yet to identify firm plans. Table 7.9 presents firm and estimated capital investments by smelter as well as estimates of the resulting effects on labour requirements. Operational

effects, including changes in labour requirements, are presented in more detail in the next section.

TABLE 7.9 - **ESTIMATED EFFECTS - SMELTER AND SINTERING PLANT COMPLEXES**

COMPANY	INVESTMENT AND COST		CONSTRUCTION PERIOD	DIRECT LABOUR IMPACT	
	Capital Investment[a]	O & M Costs[a]		Construction Phase[b]	Operational Phase[c]
HBMS	130	u/k	1990-95	860	u/k
Inco (T)	>46	>13	1989-93	u/k	>16
Inco (S)	494	(64)	1988-94	1,375	(380)
Falconbridge	30	minimal	1989-93	u/k	no change
Noranda (R)	127	5	1987-89	350	minimal
Algoma	n/a	n/a	n/a	n/a	n/a

u/k: unknown or not determinable at this time
n/a: not applicable
(): savings for O & M costs; decrease in person years for labour impact

[a] millions of 1988 dollars
[b] person years generated over the length of the construction project
[c] change in person years upon completion of the capital project

Both Inco (Sudbury) and Noranda are constructing acid plants at costs of about $137 million and $127 million respectively. Inco's acid plant will be fully operational in 1992. At Rouyn, construction on Noranda's acid plant was completed by the end of 1989. The acid plant is in a de-bugging mode currently.

In addition to the new acid plant in Sudbury, Inco has opted to substitute more efficient technology in parts of its smelting operations (Inco, 1988b). The company expects to invest $288 million on this element of its capital project between 1988 and 1994. Inco is also undertaking a mills rationalization program with provision for extra pyrrhotite rejection to reduce the sulphur input to the smelter, the amount of SO_2 generated, as well as the amount of sulphuric acid produced and sold (Inco, 1988b). This program will cost $69 million between 1988 and 1992.

Modifications at Falconbridge, mostly involving retrofits to existing equipment, are being performed during periods of opportunity between 1989 and December 1993 (Falconbridge, 1988b). The project is expected to cost $30 million, including $6.5 million toward modifying the existing acid plant.

In Flin Flon, HBMS has opted for more efficient technology to lower SO_2 emissions. This project is expected to cost $130 million between 1990 and 1994 and is contingent upon receiving financial assistance from government. About two-thirds of the investment would go toward installing the zinc pressure leaching process and one-third toward fabricating a Noranda Reactor.

Inco (Thompson) estimates that it will invest more than $46 million by the end of 1993 to lower its emissions. At least $15 million will be invested at the mill to ensure that an additional fixed quantity of pyrrhotite from Thompson type ores is rejected to tailings; $13 million will be invested at the Thompson Smelter to ensure that the low content pyrrhotite concentrates can be processed; and another sum, perhaps $18 million, will be invested to install a reliable process for treating the sulphide anode slimes. Additional investments will be required to ensure that the mill can produce concentrates with the right nickel to sulphur ratios from the ultramafic type ores. Efforts are currently underway at Inco to establish the appropriate flowsheets and their capital costs.

7.2.3 OPERATIONAL EFFECTS

In 1990, at the height of its construction phase, Inco expects its employment in Sudbury to increase by up to 510 person years as a result of its SO_2 control program (Inco, 1988c). About 1,375 person years will be created in construction over the length of the construction phase. Seventy percent of the workers required during this phase will be recruited locally. The remaining thirty percent are expected to be returning regional residents and migrants.

At the same time, operational labour requirements in the smelter will increase by 59 person years in 1990 before beginning to fall. By 1994, Inco will require 382 person years fewer than it required in 1988. However, the attrition level will more than offset the change in labour requirements, enabling Inco to add some 500 new employees in Sudbury by 1994. Inco plans to hire most of the new employees, who will be secondary school graduates, from the Sudbury region.

Also, Inco is committed to retraining employees from within its existing labour force to meet the need for technically qualified personnel at its modernized plant. Clean plant provisions contained in the construction contracts awarded and existing job training programs will elicit continuing improvements in the quality of the work environment.

In addition to the changes identified above, Inco will increase its production of sulphuric acid for market by 100 kilotonnes per year. The acid plant will be capable of fixing added quantities of high strength SO_2 gas if added quantities become available for fixation beyond 1994.

The company anticipates annual savings of about $64 million in operating and maintenance expenses once its capital projects have been completed. Lower labour, energy and chemical reagent requirements contribute to the annual savings. At the same time, oxygen flash smelters will eliminate the use of fossil fuels in the smelting process in 1994 (Inco, 1989a).

At Noranda, plans for the construction of the acid plant called for up to 350 person years of employment to be generated but the actual numbers are not available for presentation here. Both Noranda and Falconbridge anticipate that their capital projects, upon completion, will have minimal or no direct impact on annual labour requirements. Noranda, however, expects the production of over 350 kilotonnes of sulphuric acid per year to add about $5 million annually to corporate operating and maintenance expenses. Revenues from the sale of sulphuric acid are expected to cover transportation expenses from Rouyn to market, but are not expected to cover its day-to-day operating expenses at the sulphuric acid plant. Falconbridge, on the other hand, expects its control measures to have "minimal" impact on corporate operating and maintenance expenses once fully operational. The extra SO_2 fixation capacity added to Falconbridge's sulphuric acid plant is not specified.

In Manitoba, HBMS will need up to 860 more person years over the construction period (InterGroup Consultants Ltd., 1985). The experience to date at other smelters suggests that HBMS will benefit from better metal recovery as well as lower labour and energy requirements once the modernization program is completed. Similarly, employees should benefit from a cleaner working environment.

Inco (Thompson) has indicated to the Government of Manitoba that the nickel losses associated with even higher levels of pyrrhotite rejection are impractical. In addition, reports prepared for the company indicate that add-on processes which produce by-products are also financially undesirable due to high capital costs, a lack of markets for the by-products, and the distance of the smelter from potential markets in some cases. Even if markets for the products existed, the Manitoba smelter estimates that it would sustain annual operating losses ranging from $17 million to $50 million on the production of marketable by-products.

Inco (Thompson) is actively pursuing research before it will be in a position to define practical options for implementation by 1994. However, Inco suggests that annual operating expenses will increase by at least $13 million and that annual labour requirements will increase by at least 16 person years. A large part of the increase in annual operating expenses is due to the need to establish and use a supplementary energy system at the smelter. The fluid bed roasters and the converters were designed to derive energy from the oxidation of pyrrhotite in the concentrate feed. The rejection of more pyrrhotite to tailings, however, places the smelter in an energy deficit situation that requires the addition of a supplementary energy source.

Research and Development

Industry also carries research and development expenditures, sometimes shared with government, to aid development of control measures and their implementation. Our knowledge of these expenditures is incomplete; however, they add to the total cost of controlling emissions and are far from insignificant, especially given the uncertain business climate in which some of these companies operate. For example, between 1980 and 1988, Inco invested $131 million on research and development related to $S0_2$ abatement at its Subbury operations (Ontario Ministry of the Environment 1988b). During the same period it also reported net operating losses in four of the nine years.

Other companies also invested money in research and development. Falconbridge invested $40 million on research and development initiatives, leading to the improvements completed in 1978 and another $7 million between 1984 and 1988. The research and development programs at Falconbridge were established to devise economic and expeditious methods of reducing emissions; findings are applied to the commercial operations whenever the incremental benefit in reduced emissions is practical. Noranda and the Government of Quebec invested $3 million on research to design a sulphuric acid plant and to study the associated environmental impacts.

7.2.4 FINANCING EMISSIONS CONTROL

As long as more cuts in emissions are not required, the smelters face a one-shot investment commitment to control emissions. Each smelter will make changes to its operations so that it can operate at capacity, and not exceed its new legal upper limit on emissions in any year after 1993. The Government of Ontario's regulations respecting emissions at Inco (Sudbury) and Falconbridge require that they report specifically on cuts that can better the new legal upper limits, and each company has named process changes that could be made after successful R & D programs.

All smelters reported net earnings in 1988 and are in better financial situations than they were during the first half of the 1980s. Corporate net earnings (losses) are presented for 1986, 1987 and 1988 in Table 7.10 together with the cost of the control measures, financial assistance requested of government by company, and price changes expected as a result of capital projects and other measures intended to lower emissions. The increases in net earnings recorded in 1988 compared to 1987 are due to improved market conditions in 1988 for nickel, copper and zinc. Consumption of these three metals in 1988 reached record levels in the western world and, consequently, commanded about a 100 percent rise in the world prices received for nickel and copper. Improved market conditions helped most of these companies to pay for the implementation of emission controls. These market conditions are volatile and could easily change.

TABLE 7.10 - **FINANCING EMISSIONS CONTROL - SMELTER AND SINTERING PLANT COMPLEXES**

(Millions of Dollars)[a]

COMPANY	NET EARNINGS			SO_2 CONTROL MEASURES		FINANCIAL ASSISTANCE REQUESTED[b]	RATE CHANGES
	1986	1987	1988	Value	Period		
HBMS	(20.8)	39.3	28.5	130	4 yrs	43.3/43.3	n/r
Inco	0.2	18.7	735.0	540[c]	6 yrs	none	n/r
Falconbridge	70.3	73.1	341.1	30	6 yrs	none	n/r
Noranda	43.3	343.4	603.0	127	3 yrs	41.6/41.6	n/r
Algoma	n/a	40.3	80.0	--	--	none	n/r

(): represents net loss
n/a: not available
n/r: not relevant

[a] Inco's corporate net earnings are presented in U.S. dollars as per the company's annual reports
[b] federal government/provincial government
[c] combined value of control measures for Thompson and Sudbury complexes

Initially, because the smelters operate in a global context, they will absorb the costs of control measures. The federal and provincial governments, however, made some financial assistance available to the smelters for the timely implementation of SO_2 reductions. Also, operational savings incurred through time and the sale of proven technology may help companies to recover part or all of the capital investments required to control emissions. Inco, for example, developed a patentable pyrrhotite rejection process in the mid-1980s that may be marketable and Falconbridge developed a commercial converter slag cleaning process.

Inco (Sudbury) and Falconbridge have indicated to the governments that they will finance implementation of their control measures themselves. The companies have not requested financial assistance available by way of the financial provisions contained in the Canada-Ontario agreement on SO_2 reduction. Further, Inco (Sudbury) expects to save $64 million annually in operating and maintenance expenses as a result of the changes now being made at the smelter, while Falconbridge expects minimal changes in its operating and maintenance expenses. In contrast, Algoma decided in 1986 that a capital investment to reduce emissions would make the operation at Wawa uneconomic.

Noranda expects the compensating benefits associated with emissions control measures at its smelter in Rouyn will be negative; the smelter's operating and maintenance expenses are expected to increase. The company obtained repayable loans from the federal government ($41.6 million) and the provincial government ($41.6 million) to finance construction of an acid plant.

In Manitoba, HBMS intends to pursue emissions control measures. The company has requested financial assistance from the federal and provincial governments, but is delaying construction while it attempts to secure these loans.

Inco (Thompson) is pursuing research in order to define practical options for implementation by 1994. To date the company has not requested financial assistance for its capital projects.

7.3 ELECTRIC UTILITIES

Ontario Hydro, New Brunswick Power and Nova Scotia Power will regulate emission levels on a corporate or system basis as opposed to at individual generating stations or units. To meet their upper limits in 1994 and beyond, the utilities must develop strategies to lower or minimize emissions within their future or planned energy systems and not simply within their existing systems. Both New Brunswick Power and Nova Scotia Power plan to bring new coal-fired generation on stream before 1994. New Brunswick Power will add a 200-Megawatts (MW) unit at its Grand Lake station and will build another 450-MW unit at a new generating station at Belledune. Nova Scotia Power is completing construction on a new 150-MW unit at its Trenton station and will build a 150-MW unit at a new generating station at Point Aconi. Ontario Hydro, on the other hand, does not plan to add new coal-fired generation to its system before 1994, and possibly not before the turn of the century. Table 7.11 lists the existing fossil generating stations rated at about 100-Megawatts (MW) or larger in Ontario, New Brunswick and Nova Scotia.

Some background information on electrical generation and early emission control measures at the utilities is presented in Appendix 7.A.4.

Among conventional coal and oil burning plants, units that have recently come on stream or that have several years of service left on their design life are designated as new or mid service capacity. Generating stations that are approaching the end of their design service life, that is the generating stations are approaching 30 years service or more, are designated as end of service capacity. Generating capacity that is designated end of service may still be in service or it may be mothballed. This generating capacity could be either shut-down permanently or refurbished in years to come. Table 7.12 shows the estimated amount of generating capacity by plant type and service for each utility.

Advanced coal burning combustion technologies include CFB[4], PFBC[5] and IGCC.[6] The only advanced combustion unit of these types currently operated by a utility in Canada is the 22-MW CFB combustion unit at Chatham, New Brunswick, where New Brunswick Power is demonstrating the technology.

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[4] Circulating fluidized bed combustion.

[5] Pressurized fluidized bed combustion.

[6] Integrated gasification combined cycle.

TABLE 7.11 - FOSSIL GENERATING STATIONS[a], 1988

STATION (Date Commissioned)	LOCATION	CAPACITY Coal (MW)	CAPACITY Oil (MW)	UNITS (#)	OUTPUT (MW.h)	CAPACITY FACTOR (%)
ONTARIO HYDRO:						
Nanticoke (1973)	Nanticoke	4,000		8	17,882,009	47.0
Lambton (1969)	Courtright	2,000		4	8,667,305	49.1
Lakeview (1962)	Mississauga	2,400		8	4,513,447	22.5
Lennox (1976)	Bath		2,295	4	365,787	2.5
Hearn (1951)	Toronto	1,200		8	mothballed	0
Keith (1952)	Windsor	264		4	mothballed	0
Thunder Bay (1981)	Thunder Bay	300		2	1,979,199	70.4
Atikokan (1985)	Atikokan	206		1	1,306,392	69.2
Total		10,370	2,295			
NEW BRUNSWICK POWER:						
Coleson Cove (1976)	Bay of Fundy		1,005	3	4,915,127	54.6
Dalhousie (1969)	Bay of Chaleur	200	100	2	1,639,301	62.2
Courtenay Bay (1961)	Saint John		263	4	690,537	29.9
Grand Lake (1951)	Grand Lake	85		4	n/a	n/a
Total		285	1,368			
NOVA SCOTIA POWER:						
Lingan (1979)	Sydney	602		4	4,580,350	86.6
Point Tupper (1969)	Port Hawksbury	150		1	766,164	58.2
Trenton (1951)	Trenton	190		3	870,124	52.1
Tufts Cove (1965)	Dartmouth		350	3	1,420,264	46.2
Glace Bay (1951)	Glace Bay	96		5	n/a	n/a
Total		1,038	350			

n/a: not available

[a] Sulphur dioxide emissions could increase in eastern Canada if:
- o operating fossil-fired generating stations are used more fully;
- o mothballed or non-operating generating stations are refired; and/or
- o new fossil-fired generating stations come on stream in the 1990s.

TABLE 7.12 - **OVERALL ASSESSMENT OF FOSSIL GENERATING CAPACITY PREDATING THE IMPLEMENTATION OF CANADA'S SO_2 CONTROL PROGRAM**

COMPANY	OVERALL CAPACITY AND ASSESSMENT BY PLANT TYPE			SULPHUR AND SO_2 REMOVAL	
	Advanced Coal Burning	Conventional Coal and Oil Burning			
		New/Mid Service	End of Service	Sulphur	SO_2
Ontario Hydro		8,801 MW	3,864 MW	some	none
NBEPC	*	1,305 MW	348 MW		none
NSPC		1,388 MW		some	none

* 22-MW CFB combustion unit

The sulphur content of the fossil fuels purchased by Ontario Hydro, New Brunswick Power and Nova Scotia Power are presented in Table 7.13. While Ontario Hydro purchases its coals from out-of-province, both New Brunswick Power and Nova Scotia Power purchase indigenous or domestic coals. At Ontario Hydro, the average sulphur content in the coals as fired declined from 2.4 percent in 1976 to about 1.3 percent in 1988. The average sulphur content of Ontario Hydro's coals should be 1.0 percent in 1990. New Brunswick Power and Nova Scotia Power burn both domestic coals and imported oil. The fuels burned by these two utilities have a higher sulphur content than the fuels burned by Ontario Hydro.

Currently, each utility operates its fossil-fired generating stations without removing or treating SO_2 in the waste gas stream. Ontario Hydro, however, lowers the sulphur content in the coals it burns by purchasing low sulphur coals, by purchasing washed coals and by blending coals. The utility also operates two generating stations designed to burn low sulphur lignite from Saskatchewan. Nova Scotia Power, on the other hand, lowers the sulphur content in the coals it burns by purchasing washed and blended coals.

TABLE 7.13 - **SULPHUR CONTENT OF FOSSIL FUELS**
(Percent)

UTILITY	COAL	OIL
Ontario Hydro	1.3[a]	0.7
NBEPC	6.0-8.0	2.75
NSPC	2.0-3.0	u/k

u/k: unknown

[a] average as fired

Table 7.14 shows the strategies that each of the utilities are using to meet their upper limits in 1994. Generally, the existing stock of generating stations in Ontario, New Brunswick and Nova Scotia still has some years left on design life. With none of the operating stations due for replacement by 1994, the utilities are looking to reduce emissions among existing stations or units either by reducing the sulphur content of the fuels fired at some stations or by building scrubbers to capture and treat the SO_2 gas at some stations.

New Brunswick Power and Nova Scotia Power will use technologies that enable them to control 90 percent of the SO_2 gas produced at three units expected to come on stream in 1994. While Nova Scotia Power will use a clean combustion technology at its new plant, New Brunswick Power will use conventional combustion technology together with scrubbers at two plant.

Table 7.15 identifies the potential amount of SO_2 emissions control possible for new generating stations depending upon the combustion technology and the control measures to be included in the design of a new station. If a utility intends to add new coal-fired generating capacity to its energy system before the turn of the century to meet growing demand for electricity, an advanced combustion unit that burns low sulphur coal will offer the best means of minimizing SO_2 emissions and maximizing net plant efficiency. A conventional coal-fired generating unit outfitted with scrubbers to clean the gas will have 90 percent less SO_2 emissions than one without scrubbers. However, the utility building such a unit will incur a two percent efficiency penalty at the unit since electricity is required to operate the scrubber.

Over a longer period of time, utilities will attempt to accommodate lower emission levels in their demand and supply planning initiatives. At Ontario Hydro and New Brunswick Power, nuclear power and energy purchases from out-of-province or from non-utility generators have a potential role to play in future energy supply options. In Nova Scotia, the utility has looked at different methods of supplying electricity within the province. For new generation, however, the resource of choice in the "forseeable future" is coal. It is

expected that demand management initiatives will contribute to the more efficient use of electricity in all three provinces.

TABLE 7.14 - **EMISSIONS CONTROL STRATEGIES FOR EXISTING AND PROPOSED ADDITIONS TO FOSSIL GENERATING CAPACITY BY 2000 - UTILITIES**

STRATEGY	COMPANIES PURSUING STRATEGY	
	Generating Capacity	
	Existing	New
I) Fossil Generation		
a) lower sulphur content in fuels	- Ontario Hydro - NBEPC - NSPC	- NSPC
b) decrease the formation of SO_2 during combustion	- Ontario Hydro *	- NSPC - NBEPC * - Ontario Hydro *
c) capture and treat more SO_2 in the waste gas before release of the remaining gas to the atmosphere	- Ontario Hydro - NBEPC *	- NBEPC
II) Total System Generation		
a) alter generating or supply mix		- Ontario Hydro
b) demand management initiatives	- Ontario Hydro - NBEPC - NSPC	

* the utilities are evaluating these alternatives for potential application

TABLE 7.15 - REPRESENTATIVE RATES OF SO_2 EMISSIONS FOR TYPICAL NEW POWER PLANT CONFIGURATIONS

Energy Source	Plant Type	Net Plant Efficiency (%) [a]	Thermal Content of Energy Source (MJ/kg)	Emission Characteristics					
				Sulphur Content of Fuel (% by weight)	Emissions Controls (Type)	Abatement Efficiency (%)	Plant Efficiency Penalty (%) [b]	SO_2 Emission Factor (mg/MJ)	SO_2 Emissions (tonnes per MW-yr)
Coal (3% sulphur)	dry bottom, wall fired	34.0	28	3	none	0	0	1,929	180
Coal (3% sulphur)	dry bottom, tang. fired	33.1	28	3	FGD	90	2	1,929	18
Coal (3% sulphur)	AFBC (deep bubbling bed)	33.8	28	3	—	85	0	1,929	27
Coal (3% sulphur)	PFB, combined cycle	38.9	28	3	—	92	0	1,929	13
Coal (3% sulphur)	IGCC	38.0	28	3	—	99	0	1,929	2
Coal (1% sulphur)	dry bottom, wall fired	34.0	28	1	none	0	0	643	60
Coal (1% sulphur)	dry bottom, tang. fired	33.1	28	1	FGD	90	2	643	6
Coal (1% sulphur)	AFBC (deep bubbling bed)	33.8	28	1	—	85	0	643	9
Coal (1% sulphur)	PFB, combined cycle	38.9	28	1	—	92	0	643	4
Coal (1% sulphur)	IGCC	38.0	28	1	—	99	0	643	1
Municipal solid waste	mass feed boiler	20.3	11.3	0.13	none	0	0	199	31
Fuel oil, residual	boiler, opposed wall	35.2	43	3	none	0	0	1,395	126
Fuel oil, residual	boiler, front wall	34.4	43	3	FGD	90	2	1,395	13
Fuel oil, distilate	combustion turbine	28.7	45	0.3	none	0	0	133	15
Natural gas	boiler, opposed wall	35.2	51	0.002	none	0	0	1	0.07
Natural gas	conv. boiler	35.2	51	0.002	none	0	0	1	0.07
Natural gas	GT, simple cycle	28.1	51	0.002	none	0	0	1	0.09
Natural gas	GT, combined cycle	44.7	51	0.002	none	0	0	1	0.06
Geothermal steam	steam condensing	n.a.	n.a.	[c]	[c]	[c]	[c]	[c]	[c]
Enriched uranium	converter reactor	32.0	465,200	0	—	—	—	0	0

(Source: International Energy Agency, 1989)

Key: [a] Net of efficiency losses imposed by pollution-control devices.
[b] Number represents percentage by which gross plant efficiency is decreased.
[c] Geothermal steam often contains high amounts of hydrogen sulphide (H_2S), depending on the source reservoir.

FGD: Flue gas desulphurization or scrubber

7.3.1 EMISSIONS CONTROL

The utilities are implementing control measures for 1994 and beyond in conjunction with their plans to meet electricity requirements throughout the 1990s. Thus, this section and subsequent sections address emissions control measures that will be implemented by the year 2000.

To lower SO_2 emissions, the utilities have opted to displace coal with other forms of electrical generation, to purchase electricity from hydroelectric-based systems, to lower the sulphur levels in the fuels they burn, and/or to retrofit emissions control technology at existing fossil generating stations. Other measures, such as demand management initiatives, could reduce the need for generation by fossil fuels. Table 7.16 identifies the changes to capital and fuel supply, planned use of advanced or clean generating technologies and ongoing R & D initiatives for each utility.

Ontario Hydro

Ontario Hydro's plan through 1994 is to:

- promote and implement demand management initiatives;
- progressively displace coal-fired units with other forms of generation;
- lower sulphur levels in fuels by purchasing low sulphur coals, blending coals with different sulphur contents and washing all coals;
- retrofit emissions control technology; and
- use acid gas margins and reserve measures as required (Ontario Hydro, 1989b).

The demand management initiatives planned by Ontario Hydro include information-driven electrical efficiency improvements, incentive-driven electrical efficiency improvements and load shifting. These initiatives are expected to reduce supply requirements by 1,825 MW between 1988 and 1994 at a cost to the utility of about $650 million (Ontario Hydro, 1989c). Five terawatt-hours (TW.h) of fossil generation will be scrubbed in 1994 and 19 TW.h will be generated from low sulphur coal. These measures will enable Ontario Hydro to remain under its annual upper limit on emissions. Also, the utility will commission the Darlington Nuclear Generating Station, temporarily offsetting the need for some generation at coal-fired stations; increase the purchase of non-utility generation by up to 700 MW; and increase hydroelectric generation by 74 MW.

Ontario Hydro Research Division (OHRD) - SO_2 Emissions Control R & D:

o SO_2 Control only

- evaluate combustion characteristics of low sulphur coal and other fuels such as peat in the OHRD Combustion Research Facility;
- construct mini-pilot limestone scrubber to improve SO_2 removal efficiency and evaluate process models (limestone slurry scrubber support for Lambton); and
- carry out studies to improve absorber and regeneration stage efficiencies, model process, and act as research program manager for proposed 6-MW pilot plant (limestone dual alkali scrubber support for Nanticoke).

o Integrated SO_2/NO_x Control

- provide support for furnace sorbent injection demonstration for NO_x control at Lakeview;
- evaluate additives for NO_x control in limestone slurry scrubbers and limestone dual alkali scrubbers;
- participate in EPRI study on selective catalytic reduction (SCR);
- construct pilot facility partially funded by the Canadian Electrical Association; and
- evaluate SCR process.

o Particulate Emissions Control/Electrostatic Precipitators

- evaluate electrostatic precipitators (ESP) performance on low sulphur coals with flue gas conditioning;
- evaluate effect of ESP on scrubber chemistry; and
- study advanced ESP processes to permit burning lower sulphur coals without flue gas conditioning.

o IGCC

- develop processes on the bench and pilot scale for hot gas clean-up to improve efficiency and emission control; and
- establish gasification pilot facility for evaluation of Canadian fuels and process modification and improvement.

TABLE 7.16 - **EMISSIONS CONTROL - UTILITIES (1994-2000)**

Ontario Hydro

FACTORS	**TIME FRAME** Short Term	Medium Term	Long Term
Existing Capital or Plant	-flue gas conditioners (to allow use of low sulphur coal) -electricity export reduction -reactivate nuclear units down for repairs	-scrubbers	-generating mix: non-utility generation, hydroelectric generation, nuclear generation -rehabilitate generating units at R.L. Hearn
New Plants or Added Electricity Supply	-electricity purchases from other utilities	-options: nuclear, coal, natural gas, hydroelectric, electricity purchases from non-utility generators	-clean coal combustion technology options: CFB, CC, IGCC or other advanced technologies (1994+ or 2000+)
Fuel Supply and Other Resource Inputs	-coal cleaning -coal blending -low sulphur coals -low sulphur lignite		
Socioeconomic			-demand management initiatives
Research and Development			-see below

CC: Combined cycle

TABLE 7.16 - **EMISSIONS CONTROL - UTILITIES (1994-2000)**
(continued)

New Brunswick Power

FACTORS	**TIME FRAME** Short Term	Medium Term	Long Term
Existing Capital or Plant		-scrubber	
New Plant or Added Electricity Supply		-coal -non-fossil -combustion technology options: conventional coal-fired boiler with scrubber	-clean coal combustion technology options: CFB, CC, IGCC
Fuel Supply and Other Resource Inputs	-low sulphur oil		
Socioeconomic			-demand management initiatives
Research and Development			-scrubber technology assessment -demonstrate CFB combustion technology -test various fuels for use in CFB combustion units

TABLE 7.16 - **EMISSIONS CONTROL - UTILITIES (1994-2000)**
(continued)

Nova Scotia Power

FACTORS	**TIME FRAME** Short Term	Medium Term	Long Term
Existing Capital or Plant			
New Plant or Added Electricity Supply		-coal -combustion technology options: conventional coal-fired boiler with low sulphur coal	-clean coal combustion technology options: CFB, IGCC, PFBC, partial gasification
Fuel Supply and Other Resource Inputs	-low sulphur fuels -coal cleaning -coal blending		
Socioeconomic			-demand management initiatives
Research and Development			-sorbent injection demonstration -sulphur dioxide retrofit technology

Scrubber installation at existing stations will be the primary measure Ontario Hydro takes to sustain the emissions limits through to the year 2000. At the same time, Ontario Hydro will reduce the need to generate electricity from fossil fuels by purchasing electricity and by promoting demand management. In one case Ontario Hydro will purchase hydroelectric generation over a 20-year period from Manitoba Hydro. These purchases begin in 1998 at 220 MW and will grow to 1,000 MW in 2003 (Ontario Hydro, 1989e).

Incentive- and information-driven efficiency improvements may offset up to 3,500 MW of peak demand by the year 2000 (Ontario Hydro, 1989e) at a cumulative cost to the utility of about $3 billion.[7] Another 1,000 MW of demand will be moved to off-peak hours by the year 2000.

New Brunswick Power

The provincial utility is finalizing its SO_2 emissions control strategy. New Brunswick Power may burn a lower sulphur oil or convert one unit from heavy fuel oil to another fuel at Coleson Cove, the seventh largest conventional fossil generating station in Canada (NBEPC, 1989a; Canada, EMR, 1989a). The utility plans to install a 90 percent efficient scrubber at the generating station if Venezuelan orimulsion[8] is burned. Further, New Brunswick Power may burn a lower sulphur oil at Courtenay Bay and it may convert one of its units at Dalhousie to a low sulphur fuel from high sulphur domestic coal.

Circulating fluidized bed combustion technology, conventional thermal combustion technology plus a scrubber, and IGCC technology are being assessed for use at the new Grand Lake unit where New Brunswick Power plans to burn high sulphur domestic coal (NBEPC, 1989a).

The utility's early plans for the Belledune unit suggested imported low sulphur coal would be fired at the station yet to be built (NBEPC, 1988b). The utility will now build a scrubber at the plant to control SO_2 emissions. New Brunswick Power has submitted a report to the Government of New Brunswick on the use of scrubbers at this plant.

New Brunswick Power has indicated that demand management initiatives will play a role in energy planning. In spite of relatively high electricity rates, New Brunswick ranks third among provinces in its per capita consumption of electricity (MacRae, 1989). In 1987, the residential sector accounted for about 31 percent of total in-province electricity consumption; the commercial sector for 16 percent; the industrial sector for 44 percent; and losses for the remaining 9 percent. The pulp and paper industry alone accounted for 29 percent of the electricity consumed in the province.

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[7] Dollars of the year.

[8] A water-oil fuel with 3.5-4.0 percent sulphur.

Nova Scotia Power

Nova Scotia Power will reduce capacity factor operation and burn lower sulphur coals at Lingan and Point Tupper to lower SO_2 emissions at these stations by 50 percent and 75 percent respectively. At Trenton it will replace the use of 3 percent sulphur coals with 0.8 percent sulphur coals. A new Trenton unit, expected to be on line in the Fall of 1991, also will fire 0.8 percent sulphur coal.

Circulating fluidized bed combustion technology will be used at Point Aconi. When this unit comes on line toward the end of 1993 it will be the largest unit of its type in the world. The application of limestone during combustion serves to capture 90 percent of the SO_2 that forms while burning high sulphur coals. These coals will be shifted to Point Aconi from the Lingan and Point Tupper stations.

Also, Nova Scotia Power has indicated that demand management initiatives will play a role in energy planning. In 1987, the residential sector accounted for about 36 percent of total in-province electricity consumption; the commercial sector for 27 percent; the industrial sector for 30 percent; and losses for the remaining 7 percent. MacRae (1989) suggests that relatively high electricity rates in Nova Scotia already contribute to one of the lowest levels of electricity demand per capita among the provinces. Therefore, it could be more difficult to influence consumer behaviour further.

7.3.2 PLANNED CAPITAL INVESTMENTS

Ontario Hydro has identified firm plans for capital investments related to the implementation of emissions control measures at its generating stations. New Brunswick Power has indicated that it will invest in equipment to lower its emissions; however, the exact amount and/or the nature of these investments has yet to be determined. Nova Scotia Power will invest in an advanced combustion technology to be installed at Point Aconi. Table 7.17 provides information, preliminary for New Brunswick Power and Nova Scotia Power, on these capital investments and their effects on labour requirements, which are described in more detail in the next section.

TABLE 7.17 - **ESTIMATED EFFECTS TO 2000 - UTILITIES**
(Millions of Dollars of the Year)[a]

COMPANY	INVESTMENT AND COST		CONSTRUCTION PERIOD	DIRECT LABOUR IMPACT	
	Capital Investment	O & M Costs		Construction Phase[b]	Operational Phase[c]
Ontario Hydro	1,714	114	1989-2000	n/d	n/d
NBEPC	171	40	1990-1993	u/k	u/k
NSPC	130	n/s	1990-1993	u/k	u/k

u/k: unknown or not determinable at present
n/d: not determined
n/s: not specified on an annual basis but cumulative costs are expected to be about $70 million through to 2000

[a] NBEPC values are in 1988 dollars
[b] person years generated over the length of the construction project
[c] change in person years upon completion of the capital project

Ontario Hydro

The utility is installing flue gas conditioners (FGC) at a cost of $88 million for all 20 generating units at Nanticoke, Lambton and Lakeview. This equipment is required to improve precipitator performance when burning low sulphur coal at the three largest fossil generating stations. The equipment will cost $4 million to install per generating unit at Nanticoke and Lambton (Ontario Hydro, 1989b). The retrofit is more difficult at Lakeview and, as a result, the cost increases to about $5 million per generating unit at this generating station (Ontario Hydro, 1989c).

Further, the utility will construct eight 500-MW scrubbers at Lambton and Nanticoke, and four more at additional units as required, to ensure that the new upper limit on SO_2 emissions is met every year beginning with 1994. Each 500-MW scrubber will cost about $100 million to construct (Ontario Hydro, 1989b). Ontario Hydro will invest $800 million constructing these units at Lambton and Nanticoke. The capital investment may be somewhat higher if a scrubber process capable of producing a saleable by-product is selected for construction at Nanticoke (Ontario Hydro, 1988c).

Overall, Ontario Hydro estimates that it will invest about $1.7 billion on capital projects between 1989 and 2000 to reduce acid gas emissions including $146 million to install low nitrogen oxide burners at Lambton between 1994 and 1996.[9]

TABLE 7.18 - **CAPITAL INVESTMENT SCHEDULE AND COSTS - ONTARIO HYDRO (Millions of 1988 Dollars)**

GENERATING STATION	FLUE GAS CONDITIONERS				SCRUBBERS			
	Units	Date	Cost	O & M[a]	Units	Date	Cost	O & M[a]
Lambton	4	1990	16	2	2 2	1994 1996	200 200	10 10
Nanticoke	8	1990	32	4	2 2	1997 1998	200 200	10 10
Lakeview	8	1990/94	40	4				

(Source: Ontario Hydro, 1989b; 1989c)

[a] operations and maintenance

New Brunswick Power

Capital investments have yet to be identified by New Brunswick Power. In a report submitted to Environment Canada, Monserco (1989) suggests that it will cost $171 million to construct scrubbers at Coleson Cove and another generating station yet to be built. New Brunswick Power expects the capital investment will be higher than suggested by Monserco (NBEPC, personal communication).

Nova Scotia Power

The incremental capital investment at the Point Aconi station for SO_2 removal is approximately $130 million (Nova Scotia Power, personal communication).

7.3.3 OPERATIONAL EFFECTS

Ontario Hydro

The operational effects at Ontario Hydro depend upon the specific scrubber process(es) selected and the number of generating units retrofitted. Initial employment estimates for the construction of two scrubbers by year of construction are identified in Table 7.19.

[9] Dollars of the year.

Ontario Hydro expects employment will peak at about 556 person years in the third year of construction for each pair of scrubbers constructed.

TABLE 7.19 - **CONSTRUCTION PHASE EMPLOYMENT REQUIREMENTS PER PAIR OF SCRUBBERS, ONTARIO HYDRO**

YEAR OF CONSTRUCTION				
1	2	3	4	5
84	367	556	310	84

(Source: Ontario Hydro, 1988c)

For each pair of scrubbers, about 1,400 person years of construction will be created on site over a five year period. The construction of up to four pairs of scrubbers at Lambton and Nanticoke could generate up to 5,600 person years between 1990 and 2000.

Up to 7,000 person years of construction could be generated by Inco's and Ontario Hydro's SO_2 control projects in Ontario by the year 2000. This level of employment is approximately one-third the level that could be generated by the Hibernia offshore oil development project or just lower than the 9,000 person years that could be required for the Venture offshore natural gas development project (Gardner, 1985).

Upon completion, the scrubbers are expected to increase annual operating labour requirements at each site by 50 to 120 person years depending on the scrubber process selected. The impact on regional labour forces is expected to be minimal or less than one percent in the regions. In each case, Ontario Hydro reports that work force requirements will be met from available labour markets near the generating stations.

The utility also expects operating and maintenance expenses to increase once the coal-fired generating stations house both FGC and scrubbers. The scrubbers will add about $40 million a year to Ontario Hydro's expenses once installed at Lambton and Nanticoke. The need to purchase additional resource inputs and to manage by-products contribute to the increase in expenses.

Quantities of limestone will be purchased to supply reagent for the scrubbers. Ontario Hydro reports that there are five suitable limestone suppliers operating in Ontario, and that others may be prepared to enter the market if the demand warrants such action. The utility also reports that there is one suitable lime producer in the province. Energy and water inputs will be required to operate the scrubbers.

When scrubbers are used to reduce emissions, the Government of Ontario requires Ontario Hydro to construct ones that produce a saleable by-product. Lambton will produce a gypsum by-product suitable for use in the manufacture of wallboard (Canadian Electrical Association, 1989). Efforts are underway to market the by-product; however, if these efforts are unsuccessful lime may be required to fix waste by-products (gypsum) before disposal.

The limestone dual-alkali process is a leading contender for installation at Nanticoke and is capable of producing wallboard quality gypsum (Canadian Electrical Association, 1989). Soda ash may be required to regenerate the reagent if this process is selected.

About 50 person years of construction employment will be created at Nanticoke and Lakeview when FGCs are retrofitted at these generating stations (Ontario Hydro, personal communication). Once the FGC retrofit is completed, operational labour requirements will increase by about five person years each at Lambton, Nanticoke and Lakeview. In addition, the retrofit will add $0.5 million per generating unit per year to operating and maintenance expenses, or $10 million annually once all units are operational at the three stations (Ontario Hydro, 1989b; 1989c).

Premiums for low sulphur coal will also add about $57 million[10] annually to Ontario Hydro's operating expenses between 1990 and 2000. The premium is expected to increase from $32 million in 1990 to about $84 million in 1996, before decreasing to about $42 million in 2000 (Ontario Hydro, 1989c).[11]

An advisory panel on flue gas emissions control established by the Canadian Electrical Association (1989) reported that washing reduces the sulphur content in coal by up to 20 percent while adding $4 to $5 per tonne to the price of coal, or about $50 million annually to the total price of coal at Ontario Hydro. The utility, however, reports that washing removes dirt and rock mixed in with the coal during the mining process enabling it to save on shipping costs (Ontario Hydro, 1989d). Thus, these costs cannot be attributed entirely, if at all, to the cost of controlling emissions.

Overall, the utility's annual operating and maintenance expenditures will increase by as much as $114 million[12], including fuel premiums, in or about the year 2000 while meeting the upper limit on emissions. Electricity rates will increase as Ontario Hydro's revenue requirements increase.

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[10] Dollars of the year.

[11] Dollars of the year.

[12] Dollars of the year.

Ontario Hydro (1988b) estimates that the production of by-products in the year 2000 will increase by two to three times the present quantity produced using conventional, unscrubbed coal-fired units. Current by-products generate some revenue at Ontario Hydro. In 1988, Ontario Hydro sold about 20 percent of the ash it collected from the flue gases; the remaining ash was landfilled (Ontario Hydro, personal communication). Fly ash can be used to make cement or as an additive in concrete mixtures while bottom ash can be used as a road-base material. Fly ash from Lambton is sold to a local waste management company, and fly ash from Lakeview is sold to a cement company. If gypsum can be sold, some of the operating and maintenance expenses associated with its production can be recouped. If Ontario Hydro has to pay someone to use the market quality gypsum, or if it must dispose of the market quality by-product in landfill sites, the cost will add to total operating and maintenance expenses.

Research and Development

Ontario Hydro invested about $3.2 million on research and development and other tests between 1985 and the end of 1988. The company also spent $7.7 million preparing an environmental assessment report for the provincial government covering its scrubber program.

New Brunswick Power

New Brunswick Power has not identified the operational changes that will occur as it implements its control measures. The measures outlined to date suggest that the effects will include, but not necessarily be limited to:

- the expenditures/savings associated with fuel switching;
- the savings incurred by eliminating the need to transport New Brunswick coal from the Minto mine to the Dalhousie Generating Station, thereby enabling New Brunswick Power to build a scrubber at Grand Lake or employ an advanced technology;
- changes in employment during the construction and operational phases;
- changes in operating and maintenance expenses once the control measures are implemented, including the purchase of reagent for scrubbers, the purchase of additional quantities of other substances to neutralize by-products, disposal of by-products, labour costs, and consumption of energy and water to run scrubbers; and
- changes in the electricity rates charged to consumers to cover capital investments and the cost of other related initiatives.

Operating expenses are expected to increase by up to $40 million a year in 1994 (NBEPC, 1988b).

Research and Development

No figures are available to identify the amount invested by New Brunswick Power on research, development and demonstration projects for SO_2 emissions control. However, the federal Department of Energy, Mines and Resources invested $38 million at Chatham to build the CFB combustion demonstration unit for New Brunswick Power and later the utility made a $2.5 million addition to the CFB facility.

Nova Scotia Power

In 1990, Nova Scotia Power presented the Government of Nova Scotia with a 20-year plan for the reduction of SO_2 emissions. Despite a doubling of load over the 20 year period, the utility intends to reduce its emissions by 50 percent come 2010. Over the 1990s, incremental operational and maintenance expenses are expected to approach some $70 million.[13]

Research and Development

No figures are available to identify the amount invested by Nova Scotia Power on research, development and demonstration projects for SO_2 emissions control.

7.3.4 FINANCING EMISSIONS CONTROL

Eastern Canada's SO_2 control program places ongoing R & D burdens as well as financial burdens on the utilities as they sustain upper limits on emissions while adding to generating capacity. The utilities will have to remain abreast of research, development and demonstration projects that relate to clean combustion, clean fuels, sorbent injection and scrubbers. Also, the utilities will have to undertake more of their own projects to demonstrate some of these technologies and to gain their own operating experience.

Each utility is a provincial crown corporation serving many residential, commercial and industrial customers directly or indirectly, through intermediate bodies such as municipalities. The cost of emissions abatement will be recovered from these many customers. Corporate net earnings (losses) are presented for 1986, 1987 and 1988 in Table 7.20, together with the cost of the control measures and estimates of the electricity rate increases required to pay for control measures.

[13] Dollars of the year.

TABLE 7.20 - FINANCING EMISSIONS CONTROL - UTILITIES[a]
(Millions of Dollars)

COMPANY	NET EARNINGS			SO_2 CONTROL MEASURES		FINANCIAL ASSISTANCE REQUESTED[a]	RATE CHANGES
	1986	1987	1988	Value	Period		
Ontario Hydro	247.0	271.0	626.0	2,675	12 yrs	none	3.4 %[c]
NBEPC	29.3	36.0	47.6	171[b]	u/k	u/k	u/k
NSPC	(9.3)	(27.7)	n/a	130	10 yrs	u/k	n/s

(): represents net loss
n/a: not available
n/s: not specific to emissions control
u/k: unknown

[a] federal government/provincial government
[b] nothing announced as of yet - represents best guess
[c] up to 3.4 percent in 1998

Ontario Hydro

Ontario Hydro will cover its investment in capital projects and added operating and maintenance expenses by increasing its rates for electricity. The utility has estimated that its control program will require sustained increases in electricity rates between 1990 and the turn of the century (Ontario Hydro, 1989c). Initially, the control measures will result in an average 1.0 percent increase in annual rates between 1990 and the end of 1993, followed by an average 2.8 percent increase in annual rates between 1994 and the turn of the century. The rate increase will reach a maximum of 3.4 percent in 1998.

New Brunswick Power

New Brunswick Power has yet to estimate the yearly or cumulative electricity rate increases required specifically as a result of emissions control measures, and the impact this may have on its rate payers. The utility will likely follow Ontario's lead and propose rate increases to pay for some of the control measures required within its energy system.

Nova Scotia Power

Nova Scotia Power has reported losses in the fiscal years ending in 1987, 1988 and 1989. Net earnings for fiscal 1990 are expected to be some $21 million due to a 6.3 percent rate increase, effective April 1989, approved by the Board of Public Utilities. Nova Scotia Power expects its rates to rise by the rate of inflation only, despite significant capital investments and operating expenses related to SO_2 reduction.

7.4 FUTURE RESEARCH DIRECTIONS

BACKGROUND

Canada's SO_2 control program sets upper limits for provincial emissions in Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland that take full effect in 1994. The objective of the SO_2 control program is to reduce wet sulphate deposition throughout eastern Canada to a target of less than 20 kilograms per hectare per year (kg/ha/yr). This target was thought to be sufficient to protect moderately sensitive aquatic systems. Although Canada's efforts are having a significant effect even now, the current objective will not be achieved by 1994 without significant reductions in emissions from American sources.

Research will have to better define the specific spatial dimensions of the emission-transportation-deposition problem if we are going to be able to achieve and maintain target wet sulphate loadings by a given future date and in an cost effective manner. That is to say, we need to know more about how reductions in emissions at point sources in Canada (for 1994) and in the United States (for 2000) will affect future regional deposition patterns in Canada. From a policy perspective this information would become even more crucial to understanding where future emission reductions are needed, and their potential socioeconomic impacts, if regionally based deposition targets were to be adopted to protect sensitive ecosystems.

If targets based on regional sensitivity, other resources or combinations of pollutants are eventually adopted, future refinements to the upper limits on SO_2 emissions will have to be better attuned to the particular combination of pollutants and the amount of deposition threatening each ecosystem, and the nature of the ecosystem itself.

As 1994 approaches new investments in emission controls will be needed as pollutants other than $S0_2$ are controlled. Canada must not only ensure that the $S0_2$ control program produces the desired reductions in deposition but also consider how existing existing and proposed emission controls may interact. As these opportunities arise, integrated and potentially more cost-effective approaches to related air pollution and waste control problems should be assessed.

To reduce wet sulphate deposition in eastern Canada, policy makers have relied heavily thus far on an regulatory approach to lowering $S0_2$ emissions. As governments seek to integrate environmental costs into economic decision making and to provide individuals and corporations with economic incentives to alter their environmental behaviour, a broader range of policy instruments will be needed. As more attention is focused on increased cooperation and coordination of international efforts to deal with transboundary air pollution problems, further development of basic environmental and economic concepts will be required before acceptable solutions to global environmental problems are realised.

PRIORITIES

Increasing attention will have to be given to monitoring the socioeconomic implications of actions taken by the United States government to reduce emissions at sources which contribute significantly to the transboundary flow of airborne pollutants. Socioeconomic factors which should be considered in monitoring American actions include the policy instruments chosen, plant capacity, market demand, trade implications and technological change.

In Canada priority must be given to socioeconomic studies which contribute to the reduction of total emissions and waste byproducts. At the same time, socioeconomic studies should also contribute to the consideration of the need, cost and feasibility of implementing interim mitigation measures.

Consideration must be given to developing and strengthening assessments of:

- o industrial opportunities and measures required to lower emissions (including early recognition of barriers to the use of cleaner industrial processes, the need for support for research and development, and the choice of the best mix of regulatory, negotiated and economic measures necessary to achieve the desired response from industry)
- o environment - economy tradeoffs that will occur with the choice of emission control measures at the corporate level
- o socioeconomic impacts on communities and regions due to emission control programs, and
- o potential LRTAP mitigation measures, especially as they relate to the effects of acidic deposition on natural or cultural resources.

Industrial Performance

The experience in Canada is that the circumstances in which each company finds itself and the timeframe within which they can reduce emissions of pollutants vary considerably. Therefore almost a company-by-company assessment would have to be undertaken to identify opportunities for reducing SO_2 emissions and for reducing emissions of other pollutants of concern. Current plant condition and the availability of suitable combustion or mineral recovery technology would have to be taken into consideration.

If emissions start to rise because of an increase in the number of emission sources or the level of economic activity, then further action may be necessary to contain emissions. Opportunities for promoting better environmental performance which contribute to corporate economic objectives such as increased productivity, energy efficiency and better resource usage or recovery should be identified and evaluated. Socioeconomic research is required to identify the best means of improving corporate environmental performance:

- o when the capital costs of emission controls are not offset by operating and maintenance savings
- o when increased costs can not be passed on to customers in the form of price or rate increases
- o when revenues from the sale of byproducts does not recover costs.

Barriers to corporate action, such as the lack of financing, risk perception and uncertainty about the government's environmental requirements should also be addressed at the same time.

Market-based approaches which provide needed incentives to industry to improve their environmental performance should also be evaluated. Traditional regulatory approaches to emission controls often ignore economic disincentives. Market allocation measures, such as emission trading, for example, could be useful in some cases to minimize potential employment losses, adverse impacts on competitiveness and profitability. Those industries/utilities that are able to better their assigned targets because of fluctuations in production or the use of more efficient combustion technology or industrial processes would be able to save emission rights for future use or sell emission rights which are surplus to their requirements. Less efficient emission sources would lose any cost advantage from polluting and would have to "buy" the time they need to implement the necessary process changes required to improve their performance. Still other sources may only require temporary discharge permits from time to time during peak demand periods or unexpected breakdowns. The bottom line of any socioeconomic assessment, however, is whether or not market-based approaches to emission controls would be any more cost-effective and environmentally sustainable then traditional regulatory approaches. Public acceptability of these measures and their distributive effects should also be assessed at the same time.

Insomuch as market-based incentives may help to achieve emission control targets at a lower cost, demand management initiatives, which provide room for future economic growth, may also have to be assessed to help Canadians live within these caps. Demand management initiatives include energy conservation, consumer education and product substitution. Such initiatives may help Canadians to consolidate the environmental gains that have been made from the current emission control program.

Given the long lead time required to plan and implement emission controls, any change in the scope of emission controls should be resolved at the earliest possible date to allow industry to make the necessary adjustments to their strategic plans. Further reductions in $S0_2$ emissions may be required. Complementary air pollution abatement needs, such as reductions in NOx/VOC and CO_2 emissions should be also be considered. Industry should be helped to develop the most cost-effective emission control strategy where possible because the joint costs of emission controls of multiple pollutants are likely to be less than the control costs for individual pollutants.

Waste Reduction

Energy and resource conservation, and waste reduction are increasingly important considerations when emission control options are being evaluated. Emission controls affect the demand for energy, water and reagents such as limestone. Pollution may be taken out of the air only to be transferred to the soil or water in another form. Therefore the net impact of emission controls on industrial use of resource inputs and the production of waste should be assessed. Over time, by using better combustion technology and production processes, industries implementing emission controls should be encouraged, at the same time, to reduce primary resource demand and the net volume of wastes disposed per unit of output. By estimating the potential supply and demand for marketable byproducts, possible sales and revenue, stockpiling and disposal costs could be assessed. This information could be used to determine the need for policy initiatives and possible incentives for the reuse of byproducts, such as scrubber-produced gypsum.

Socioeconomic Impacts

The adjustment of Canadian industry to the implementation of emission controls should be fully documented. Emission controls will result in some cases in improvements in process efficiency (better use of energy, improved resource recovery and lower operating costs), production of marketable byproducts and the resale of innovative technology. In other cases, emission controls may result in increased operating costs and eventually, price or rate increases. Comparisons of actual expenditures with a company's or utility's planned or projected expenditures would be instructive. Business and public concern about the socioeconomic impacts of controls could in part be allayed by documenting what we have learned from experience.

Control measures that achieve similar emission reductions may have dissimilar socioeconomic impacts. Capital investment and procurement expenditures for different abatement strategies will have an impact on controlled industries: output levels; operating costs; sales and revenues; job and income creation; price and rates charged. These expenditures stimulate the manufacturing and service sectors of the economy. Innovative emission control technology itself is a saleable commodity. Therefore, the net socioeconomic impact of proposed emission control initiatives should be known to policy makers. Moreover, the growing contribution of air pollution abatement activities to the Canadian economy and the benefits of a cleaner environment should be publicly recognized and reported.

Mitigation Measures

Although emission controls have been adopted as Canada's first line of defense, the possibility that current and proposed emission controls may not be adequate in the near term or sufficient to protect the most sensitive ecosystems and natural resources has

been recognized. Socioeconomic analysis can contribute to identifying the need for intervention and to assessing the economic feasibility of proposed mitigation measures such as restocking, liming or fertilization. Natural resource managers will need tools to assist them in the choice of the most cost effective application of these mitigation techniques.

Not only our natural but our cultural heritage may require interim protection while emission controls take effect. Mitigation measures may be necessary to arrest the current deterioration and to protect heritage buildings and outdoor monuments against unacceptable levels of exposure. Socioeconomic research can contribute to defining the need and cost of conservation requirements resulting from acidic deposition and other forms of air pollution. Once the scope of the funding requirements are known, the ability of owners to finance and undertake needed repairs and restoration work, and also the corresponding need for financial incentives can be assessed. The conservation work necessary to protect heritage structures from acidic deposition could make a substantive contribution to the growing rehabilitation industry. Expenditures for the rehabilitation of older structures are now recognized to exceed the value of new construction in Canada. Moreover, historic properties and landmarks also play a major role in the tourism industry. Therefore the direct and indirect impacts of construction, employment and purchasing expenditures associated with conservation efforts could be considerable.

APPENDICES

7.A.1 BASICS OF SMELTING

The basics of metal recovery and the main pollutants associated with metal recovery are described below.

Mining

Metals such as copper, zinc, nickel and lead begin as ores in the ground. These ores contain sulphide minerals which are complex mixtures of one or more of the recoverable metals and sulphur. Ores are extracted using either surface or underground mining techniques. Once extracted, the ore is crushed and ground to the consistency of sand and is then sent to a mill.

Milling

In the mill, impurities are removed by various physical and chemical processes depending on the type of ore. This stage is known as concentration and the product is called concentrate. From the mill, the concentrate is then sent to the smelting facility for additional processing to produce a finished metal.

Roasting

Pre-dried concentrate is fed into a large cylindrically shaped vessel which is either an open-hearth roaster or a fluid-bed roaster. Air and a supplementary fuel are blown in to the roaster to drive the sulphide off as sulphur dioxide. The product from roasting, called calcine, is then sent to the smelter.

Smelting

The smelter is a large steel walled furnace with an interior lining of highly heat resistant brick (called refractory). The smelter is heated either electrically or with a supplementary fuel such as oil or natural gas. Here, at a temperature greater than the melting point of the desired metal, sulphide minerals are further oxidized. Sulphur dioxide is liberated; metallic impurities (usually iron) are converted to slag by adding silica; and the metal values are concentrated further in a more recoverable form referred to as matte. Slag and matte are removed from the furnace. Slag is sent for disposal and the metal-rich matte is sent to the converter for further processing.

Converting

The conventional Pierce-Smith converter is a cylindrically shaped, horizontally oriented vessel smaller than the furnace. Some facilities contain top-blown rotary converters which are able to rotate on both longitudinal and vertical axes. Here, with application of air and fluxing agents, most of the remaining impurities such as iron and sulphur are removed

from the metal-rich matte as a slag before final refining is performed. The metal matte produced by the converter is 96 to 98 percent pure.

Refining

Refining is another upgrading process. It can be either electrochemical or pyrometallurgical and increases the purity of the metal to over 99 percent. After refining the metal is available for use.

Main Pollutants from Smelting

Gases are produced during the roasting, smelting (furnace) and converting stages of smelting operations. The most significant pollutants generated by all smelting processes are:

- SO_2 gas;
- volatized or vaporized metals with low melting points such as arsenic and mercury;
- particulate matter;
- dusts; and
- fumes.

Sulphur dioxide gas is produced by the oxidation of sulphide minerals present in the concentrate. Air supplied to the roasting, smelting and converting stages of the smelting operations determines the volume and concentration of SO_2 gas produced.

Particulate matter consists of very small particles produced during the turbulent and hot operating conditions required for roasting, smelting and converting. Particulate matter ranges in composition from inert particles to oxides and sulphates of heavy metals such as cadmium, cobalt, copper and nickel. The exact composition of these particles depends on the metals contained in the concentrate and the smelting process used.

Because pyrometallurgical processes are essentially dry, effluents are of minor importance. The principal sources of effluents at a smelter are:

- runoff from the smelter yard;
- bleed streams from the waste heat recovery boiler circuit;
- solid-liquid separation from gas cleaning equipment; and
- contaminated liquid effluents from the gas cleaning section of an acid plant where sulphuric acid is produced from SO_2.

Wastewater from the gas cleaning section of an acid plant is acidic and contaminated with heavy metals such as zinc, lead and copper. The wastewater is treated by simultaneously neutralizing its acidity and removing metals. Treated effluents are either discharged to a tailings pond or to the receiving environment.

The main solid waste from smelting is slag. No further valuable metals can be extracted from this material using existing technologies. Slag is regarded generally as being inert, and is collected and deposited at designated areas called slag dumps. Surface runoff from slag dumps generally does not pose an environmental concern.

Note: The description is extracted from Paine (1988).

7.A.2 EARLY CONTROL MEASURES - SMELTERS

As seen in Section 7.0 actual SO_2 emissions at Inco (Sudbury), Falconbridge and Noranda smelters decreased during the first half of the 1980s. Although uncontrollable circumstances[14] caused some portion of these reductions, concrete steps were taken at Inco (Sudbury) and Falconbridge to reduce emissions during the 1970s and the 1980s. This appendix summarizes some of the measures taken by Inco (Sudbury), Falconbridge and Algoma to reduce their emissions in the 1970s and 1980s.

During the 1970s, Inco (Sudbury) reduced emissions by closing the Coniston smelter, building additional acid plant capacity at its Iron Ore Recovery Plant, building the Clarabelle concentrator, and modifying the Copper Cliff concentrator for more efficient pyrrhotite removal (Ontario/Canada Task Force on Inco and Falconbridge, 1982). With these changes, the company improved SO_2 containment from about 30 percent in the late 1960s to about 70 percent in the late 1970s. Pyrrhotite concentrate is treated at the Iron Ore Recovery Plant where iron from pyrite and pyrrhotite concentrate is recovered (Canada, EMR, 1989).

Falconbridge acted in the mid-1970s and the 1980s to control SO_2 emissions at its Sudbury operations (Falconbridge, 1988b). It completed a plant modernization project in 1978, enabling the smelter to capture SO_2, clean it and send it to an acid plant. Total annual emissions decreased in the latter half of the 1970s from previous levels of about 350 kilotonnes in the early 1970s to about 150 kilotonnes at a capital cost of $175 million. Subsequently, the working conditions at the smelter have improved, productivity has improved, metal recovery has improved and operating expenditures have decreased.

At the same time, Falconbridge began to improve the separation efficiency of pentlandite and pyrrhotite at the Falconbridge Mill (1977-1982). Since then, ongoing changes at the Strathcona Mill have improved the separation of sulphide minerals at this second mill. The amount of nickel lost in pyrrhotite rejected to tailings has decreased; recovery of valuable minerals from a low pyrrhotite ore has increased without affecting overall pyrrhotite rejection; and the copper content of smelter concentrate feed has decreased, subsequently reducing SO_2 emissions. Overall, Falconbridge reduced SO_2 emissions from about 15 tonnes per tonne of nickel produced prior to 1955 to less than 2 tonnes per tonne of nickel produced in 1988. In early 1988, Falconbridge closed the Falconbridge mill and it has no plans to reopen it (Falconbridge, 1988b).

During the mid-1980s, weak markets forced a permanent down-sizing at Algoma's iron ore sintering plant in Wawa. This action lowered SO_2 emissions at the plant below the annual 125-kilotonne upper limit identified in the provincial regulation. Algoma reported

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[14] Uncontrollable circumstances include: the cyclical nature of the metal business, changes in the international prices for base metals (copper, nickel, zinc and lead) and competition for markets from smelters throughout the world.

that the decision to lower production at Wawa minimized the social costs to the community since the alternative was to shut down operations at the sintering plant (Ontario Ministry of the Environment, 1989b).

7.A.3 DEVELOPMENTS IN DOMESTIC SMELTER TECHNOLOGY

Pyrrhotite Rejection

Pyrrhotite, an iron sulphide mineral present in magnetic and non-magnetic forms in all nickel and copper ores, is a significant source of sulphur. During smelting operations, the sulphur in pyrrhotite is converted to SO_2. Conventional ore processing operations remove much of the pyrrhotite from the concentrate before it is shipped to the smelter. However, if additional pyrrhotite can be removed during the milling operation there will be less sulphide mineral available to form SO_2 during the roasting, smelting and converting stages. The principle of pyrrhotite rejection is the selective removal of as much pyrrhotite as possible (while minimizing metal losses) from the concentrate before the three smelting stages.

Increased Degrees of Roasting

Iron sulphide impurities are converted to iron oxide and SO_2 gas during roasting. Iron oxide combines with silicate minerals (added as a 'flux') in the furnace to form an iron-silicate slag. Increasing the degree (or extent) of roasting produces greater amounts of SO_2 in a stage of the smelting process that allows easier and more efficient capture of this gas. Also, the SO_2 gases are more amenable to capture if a fluid bed roaster is used rather than another type of roaster.

Flash Smelting of Combined Copper/Nickel Concentrates

This technology applies principally to non-ferrous smelters that smelt copper and nickel ores in two separate circuits. With flash smelting technology, the copper and nickel concentrates are combined and smelted together in a flash furnace. A distinguishing feature of the technology is the integration of roasting and smelting stages into one unit - the flash furnace. Another important feature is its use of pure oxygen or oxygen-enriched air as opposed to a supplementary fuel. Flash smelting produces low volumes of highly concentrated and easily captured SO_2 gas.

Increased Production of Sulphuric Acid

Roasting, smelting and converting produce varying volumes and concentrations of SO_2. The greatest volume of SO_2 is produced during the roasting of concentrates. Lesser volumes of SO_2 are produced during the smelting and converting stages. Sulphur dioxide produced from roasting the concentrates can be used to make sulphuric acid. The variable strengths and volumes of the gases produced by conventional smelting and converting operations, however, often determine the suitability and degree of difficulty in capturing the gases from these stages.

Smelters capture SO_2 and make either liquid SO_2 or sulphuric acid as one means of reducing SO_2 emissions. This practice is well established and produces a marketable by-product.

Note: The description is extracted from Paine (1988).

7.A.4 ELECTRICAL GENERATION AND EMISSION CONTROL

Coal-fired and oil-fired generating units contribute to total installed generating capacity at different rates in each province. The relative contribution of these generating units to electrical energy production also varies by province. Table 7.A.1 shows the percent contribution of fossil-fired generating units to installed generating capacity and electrical energy production by province. The percent contribution of each utility to total utility SO_2 emissions in eastern Canada is presented as well. Data for Prince Edward Island and Newfoundland are included in the table since both of these provinces have an annual limit to sustain beginning in 1994. The utilities are also the major sources of emissions in both provinces. Data for Manitoba and Quebec are included for comparative purposes.

TABLE 7.A.1 - **PERCENT CONTRIBUTION OF FOSSIL-FIRED GENERATING UNITS TO PROVINCIAL GENERATING CAPACITY AND ELECTRICAL ENERGY PRODUCTION, 1988**

PROVINCE	CONTRIBUTION OF FOSSIL FIRED GENERATING UNITS TO		CONTRIBUTION TO UTILITY SO_2 EMISSIONS IN EASTERN CANADA
	Installed Generating Capacity	Electrical Energy Production	
Manitoba	12%	6%	0.5%
Ontario	41%	25%	47.0%
Quebec	3%	1%	0.2%
New Brunswick	54%	50%	24.9%
Nova Scotia	84%	88%	22.7%
PEI	100%	100%	0.2%
Newfoundland	3%	11%	4.6%
Total			100.1%

More detailed information for all fuel types (hydro, coal, nuclear, oil and natural gas) is provided for each province in the next two tables. Table 7.A.2 identifies installed generating capacity by fuel type and province, and Table 7.A.3 identifies electrical energy production by fuel type and province. If only coal and oil are considered, coal is the main fuel used for electrical energy production in Manitoba, Ontario and Nova Scotia; oil is the main fuel used for electrical energy production in Quebec, New Brunswick, Prince Edward Island and Newfoundland.

TABLE 7.A.2 - INSTALLED GENERATING CAPACITY BY FUEL TYPE, 1988[a]

PROVINCE	HYDRO	COAL	NUCLEAR	OIL	NATURAL GAS	TOTAL
Manitoba	3,641	466	0	14	4	4,125
Ontario	7,775	10,935	11,221	2,651	373	32,955
Quebec	25,585	0	685	980	8	27,258
New Brunswick	903	356	680	1,532	0	3,471
Nova Scotia	386	1,201	0	758	0	2,345
PEI	0	20	0	122	0	142
Newfoundland	6,644	0	0	782	0	7,426

(Source: Canada, EMR, 1989a)

[a] Megawatts (MW)

TABLE 7.A.3 - ELECTRICAL ENERGY PRODUCTION BY FUEL TYPE, 1988[a]

PROVINCE	HYDRO	COAL	NUCLEAR	OIL	NATURAL GAS	TOTAL
Manitoba	15,379	924	0	0	5	16,308
Ontario	38,314	35,033	67,552	510	1,334	142,743
Quebec	143,391	0	5,282	332	0	149,005
New Brunswick	2,580	1,732	5,342	6,118	0	15,772
Nova Scotia	1,107	6,033	0	1,752	0	8,892
PEI	0	133	0	85	0	218
Newfoundland	39,731	0	0	1,419	0	41,150

(Source: Canada, EMR, 1989a)

[a] Gigawatt-hours (GW.h)

The amount of fossil energy generated, the efficiency of the units, the level of emissions control, and the sulphur content of the fossil fuels fired are the determinants of actual SO_2 emissions. Several uncontrollable circumstances could also affect emissions levels, including changes in climate, breakdowns at non-fossil generating stations, delays in bringing a new generating station on stream or out-of-province shortages. Any of these factors could temporarily increase a utility's dependence on coal-fired or oil-fired generating units in a given year, subsequently increasing the utility's level of SO_2 emissions in that year.

Ontario Hydro

Currently, electricity is produced by fossil generation at the Lambton, Nanticoke, Lakeview, Thunder Bay, Atikokan and Lennox generating stations in Ontario as well as at some smaller diesel units in remote communities. These stations provide a ready supply of peak and intermediate load electricity when nuclear and hydroelectric sources of electricity are operating at full capacity and shortfalls of electricity occur. For example, Lakeview operated from 1 to 10 percent of the time to meet peaking needs in 1988 whereas Lambton operated up to 40 to 60 percent of the time as near base load units to meet steady demand.

Nanticoke, Lakeview and Lambton produce about 93 percent of the electricity generated by fossil fuels in Ontario Hydro's system. These three plants are among the five largest conventional fossil generating stations in Canada (Canada, EMR, 1989a). Nanticoke, the largest of Ontario Hydro's coal-fired generating stations, burns a blend of medium sulphur U.S. coal and very low sulphur western Canadian and U.S. coal, while Lambton and Lakeview burn medium sulphur U.S. coal. The Thunder Bay and Atikokan generating stations burn low sulphur lignite from Saskatchewan. Lennox, the third largest conventional thermal generating station in Canada, is fuelled with residual oil that has a 0.7 percent sulphur content. Currently, all units at the Lennox Generating Station are operational. A non-operating plant, Richard L. Hearn, is the sixth largest conventional thermal generating station in Canada. This station is designed to burn coal and natural gas, and will likely burn natural gas when it is rehabilitated.

During the mid-1980s, nuclear generation replaced some coal-fired generation at Ontario Hydro, thereby reducing the utility's SO_2 emissions. Further reductions were achieved by burning low sulphur coals at Nanticoke and Lambton and by purchasing electricity from Manitoba and Quebec (Ontario Hydro, 1988c). In 1989/90, some electricity was purchased in the United States. More costly low sulphur coals are purchased and all coals are washed to reduce emissions. The low sulphur coals cost from 5 to 80 percent more than medium sulphur coals, and are obtained from mines in Alberta, British Columbia and the United States. As fired, western Canadian bituminous coals have an average sulphur content of 0.23 percent. The three largest generating stations, however, cannot support the combustion of low sulphur coals alone and must burn a blend of coals. Low, regular and medium sulphur coals (0.8, 2.44 and 1.72 percent sulphur as fired) are obtained from mines in the United States.

Coal is a swing fuel in Ontario Hydro's energy system. Small changes in the energy system can amplify the amount of coal used to generate electricity and the quantity of SO_2 produced. Ontario Hydro (1988c) reports several factors that could lead to emissions changes by themselves, or in combination with other factors, and the possible impact these factors may have on the combined annual emissions of SO_2 and NO_x:

- the loss of one nuclear unit for a period of one year can result in a 50-90 kilotonne increase in acid gas emissions;
- a one year delay in transmission from the Bruce nuclear generating station can result in a 45 kilotonne increase;
- a one percent increase (decrease) in demand for three years can result in a 60 kilotonne increase (decrease);
- lower (higher) water levels in the province can result in a 35-70 kilotonne increase (decrease);
- the purchase of non-utility generation can result in a 50-100 kilotonne decrease;
- loss of the Bruce load and generation rejection system can result in a 250 kilotonne increase;
- the loss (addition) of electricity purchases can result in a 45-90 kilotonne increase (decrease); and
- a decrease (increase) in demand management initiatives can result in a 100 kilotonne increase (decrease).

New Brunswick Power

During the 1980s, New Brunswick Power contracted with Hydro-Quebec to purchase cheaper hydroelectric generation from Churchill Falls, Labrador, to replace high cost fossil generation for in-province use. These purchases from Hydro-Quebec have enabled New Brunswick Power to avoid some emissions. New Brunswick Power (1989b) reports that the amount of surplus energy it purchases from Hydro-Quebec has diminished historically and purchases are expected to decline further since Hydro-Quebec can obtain higher prices for its electricity in U.S. markets. In 1994, New Brunswick Power plans to substitute new domestic generating capacity for the purchases from Hydro-Quebec.

New Brunswick Power proposes to increase its generating capacity by constructing multi-fuelled (coal and oil) thermal generating units. Between 1989 and 1998, two 450-MW units, a 200-MW unit and a 25-MW unit will be added to the provincial energy system (Canada, EMR, 1989a). In addition, the utility is installing five 100-MW combustion turbine units to meet peak demand. The utility's goals are to provide a secure supply of power at competitive cost with an acceptable financial risk and an acceptable environmental impact (NBEPC, 1989b).

New Brunswick Power (1989c) projects that it could emit 170 kilotonnes of SO_2 in 1995 if control measures are not implemented. This is above the annual 130-kilotonne goal set for the utility by the provincial government. Of the projected total, about 70 kilotonnes would be emitted by firing New Brunswick coal in units at two generating stations (280 MW), another 75 kilotonnes would be emitted from oil-fired units (1,360 MW), and about 25 kilotonnes would be emitted by firing imported, low sulphur coal at a new generating station to be built at Belledune (450-MW). Stations burning New Brunswick coal (8 percent sulphur content) and imported No. 6 oil (2.75 percent sulphur content) contribute

the most to the utility's emissions. Existing sources alone would place the utility above the annual goal.

Nova Scotia Power

Nova Scotia's electrical energy system was originally based on coal. After World War II, oil became the predominant fuel in the utility's energy system. The fuel remained dominant until the OPEC induced price shocks of the early 1970s. Oil prices rose so dramatically in the 1970s that Nova Scotia Power found it less costly to build and operate new coal-fired generating stations than it was to fuel existing oil-fired stations. In addition, the National Energy Program (1980) noted: "There is a need to find ways in which the large reserves of local coal can contribute to off-oil objectives and to local economic development on a viable, lasting basis." Nova Scotia Power began a capital intensive off-oil program which ended in 1987 with the conversion of Point Tupper 2 to coal.

Nova Scotia Power expanded its investigation of emerging coal-fired technologies with the potential to reduce SO_2 and NO_x emissions as a result of heightened public concern about the effects of acidic deposition on natural and cultural resources. The utility, in conjunction with the Department of Energy, Mines and Resources, began construction of an experimental rig in 1982 for testing erosion and corrosion in a fluidized bed environment. This program, successfully completed in 1985, afforded Nova Scotia Power the opportunity to gain experience with fluidized bed technology. This tied in with a multi-phase CFB research program, technical and economic feasibility studies, and pre-engineering work for the design of a 150-MW unit. Indigenous coal and limestone characterization tests were conducted at the 22-MW CFB unit in Chatham, New Brunswick.

The major fossil-fired generating stations in Nova Scotia are Lingan, Point Tupper, Trenton, Glace Bay and Tufts Cove. These stations supply nearly 90 percent of Nova Scotia Power's electricity requirements. While Tufts Cove burns heavy oil, the other four generating stations burn domestic coal. The units generally operate in the base and intermediate mode, with peaking electricity supplied by hydroelectric and combustion turbine generation.

Nova Scotia Power plans to increase its generating capacity by constructing six 150-MW coal-fired generating units (Canada, EMR, 1989a). These units will come on stream between 1991 and the year 2000. Nova Scotia Power may possibly add four 300-MW units for the U.S. market.

SO_2 Emissions Reductions in Prince Edward Island

In Prince Edward Island, the Maritime Electric Company generated most of the province's electricity requirements up until 1980. The utility purchased a 10 percent ownership interest in one of New Brunswick Power's coal-fired units at Dalhousie in 1981/82 to help stabilize its own energy costs and to reduce the province's dependence on oil. Prince Edward Island currently obtains a large portion of its electricity requirements through direct purchases from New Brunswick Power and through its equity position in Dalhousie. Island capacity is reserved for stand-by and peaking capacity. This action results in lower annual SO_2 emissions for the province.

SO_2 Emissions Reductions in Newfoundland

In Newfoundland, the combustion of fuel oil is the largest source of SO_2 emissions. The provincial government anticipates that province-wide emissions will decrease with decreasing industrial reliance on fuel oil and with the use of a lower sulphur fuel oil for electric generation.

Expected Growth in Electricity Demand

The demand for electricity is expected to grow in all provinces (Canada, EMR, 1989a.) Energy, Mines and Resources expects the average demand for electricity to increase as follows

- 1.6 percent per annum in Quebec;
- 1.8 percent per annum in Ontario and Prince Edward Island;
- 2.1 percent per annum in Manitoba;
- 2.4 percent per annum in Newfoundland;
- 2.7 percent per annum in New Brunswick; and
- 2.9 percent per annum in Nova Scotia.

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